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BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
COMMISSIONER-CHAIRMAN
JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY AND FOR RELATED APPROVALS, AUTHORIZATIONS AND WAIVERS.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1602 ET SEQ.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165

NOTICE OF FILING DIRECT TESTIMONY OF FREDERICK M. BLOOM AND COMMONWEALTH'S COMMENTS, LIST OF WITNESSES AND SUBJECT AREAS

Pursuant to the Commission's Procedural Order dated June 23, 1999, Commonwealth Energy Corporation ("Commonwealth") provides notice of the filing of the Direct Testimony of Frederick M. Bloom, the Comments of Commonwealth, its Witness List, and the Subject Areas of the Testimony of Mr. Bloom, as presented below.

COMMENTS OF COMMONWEALTH

Tucson Electric Power Company ("TEP") is proposing a framework of tying wholesale generation price indices to the collection of the competitive transition charges ("CTC"). This approach has failed to promote competition in every state where it has been tried before. In addition, TEP is further complicating the process by including complex formulas for computing a wholesale-related adder and the imputed costs of must-run units. The net result is no significant "shopping credits"and virtually no certainty for customers who desire choice.

Commonwealth urges the Commission to reject the Settlement. In its place, the Commission could simply order TEP to reflect "shopping credits" in the amounts presently being paid by customers. Second, the Commission should urge TEP to divest of its generation assets through an open bid process, so as to reduce the stranded costs of TEP. If such divestiture is not forthcoming, the Commission could order the recover of an interim CTC based upon the evidence in this proceeding, with a review of stranded cost recovery at a later date. At that time, the Commission could order the appropriate adjustments to the CTC depending upon actual electric market conditions.

Approval of this Settlement would, in essence, close the TEP service area from meaningful electric competition until the year 2008. This conclusion is supported by the previous testimony in these dockets, some of which is highlighted here.

TEP's Stranded Costs Are Overstated, Particularly Because TEP Retains Ownership of Its Generation Assets

The Residential Utility Consumer Office ("RUCO") responded to TEP's stranded cost filing in September of 1998. It relied on its consultant, Dr. Richard Rosen in claiming that TEP had only $84.1 million in stranded costs. RUCO said:

> In contrast to the mysterious methodology proffered by TEP, RUCO witness Dr. Richard Rosen's stranded cost methodology was explained at length in Dr. Rosen's January, 1998 testimony in ACC Docket No. RE-00000C-94-0165. Dr. Rosen estimated that the TEP's strandable generation costs at that time were $513.4 million dollars over the time period 1998-2020. However, beginning in 1998 they decline rapidly as TEP ratepayers continue to pay above-market generation rates as they have in the past. TEP's estimate is for the time beginning when the plants change hands, presumably at the beginning of 2001, through the life of the assets. Therefore, to make Dr. Rosen's estimate comparable to the TEP estimate, the over-market payments for the years 1998, 1999, and 2000 must be removed from Dr.

> Rosen's estimate. This is shown on page one of Attachment RUCO-1. The result is estimated positive stranded costs with a 1998 value of just $84.1 million dollars.
>
> Comments of the Residential Utility Consumer Office and Request for Hearing, *A.C.C. Docket No. E-10933A-98-0471* (Sept. 21, 1998) ("RUCO Comments") at 2.

RUCO's "Analysis and Recommendations," as set forth in the September 21, 1998 filing, is attached hereto as Attachment Commonwealth No. 1.

RUCO may attempt to disavow Dr. Rosen's opinion, as it did during the Arizona Public Service Company settlement proceedings. However, RUCO relied on Dr. Rosen's expertise after the January 1998 generic stranded cost proceedings, when it filed its own Comments on the Proposed APS/TEP Settlement last September.

The CTC Using the Palo Verde Wholesale Price Was Criticized by the Parties Previously

RUCO previously criticized the Palo Verde wholesale price as not reflecting the local retail market price in the TEP service area. RUCO Comments at 3. RUCO further suggested that "this local retail market price for each class is also the appropriate standard offer generation rate for that class." *Id.* Commonwealth concurs that the generation costs of TEP should be used as the generation shopping credit.

AECC likewise was critical of the CTC being tied to the wholesale price of power sold at Palo Verde. In September of 1998, AECC described this method as "an extreme version of the Net Revenues Lost approach to calculating stranded cost recovery." Written Comments and Request for Hearing Regarding Application of Tucson Electric Power Company for Approval of Its Plan for Stranded Cost Recovery and For Related Approvals, Authorizations and Waivers Submitted by ASARCO Incorporated, Cyprus Climax Metals Company, Enron Corp., and AECC, *A.C.C. Docket No. E-01933A-98-0471* (Sept. 21, 1998) at 4.

AECC concluded that this Net Revenues Lost approach "completely defeats the purpose of moving to a competitive market." *Id.* Commonwealth continues to share these views that the Market Generation Credit and CTC approach proposed by TEP is an <u>extreme</u> version of the Net

Revenues Lost approach. So extreme, it is likely that no choice will be made available to the vast majority of TEP's customers.

RUCO Previously Said the Adder Was Inadequate

If It Did Not Include Retail Marketing Costs

RUCO addressed the adder in its September 1998 comments. "All ESPs offering retail generation service in TEP's service district will incur significant costs in addition to the wholesale cost of generation." RUCO's Comments at 3. RUCO reported these estimated additional costs, as presented by Dr. Rosen during the generic hearing on stranded costs. Dr. Rosen said the adder should range from 0.82 to 1.18 cents per kWh for small customers and from 0.54 cents to 0.85 cents per kWh for large customers. RUCO went on to say "the largest component of these 'retail adders' is the administrative and general costs of providing retail service. The remainder consists of associated customer services, marketing and advertising, ancillary services (not including those mentioned in FERC Order 888), profit, and taxes (Exhibit RAR-3)." *Id.*

RUCO's testimony in this Proposed TEP Settlement conflicts with its prior Comments. In September of 1998, RUCO said: "If the standard offer generation rate is too low to allow alternative ESPs to cover the wholesale cost of generation plus their retailing expenses, then 'full generation competition as soon as possible,' one of the Commission's stated objectives in addressing the stranded cost issue (Decision 60977, p. 8), will not be accomplished. In fact, there will probably not be any retail competition, as is generally the case in California, Massachusetts and Rhode Island, which made this same mistake in using a wholesale price of generation to set the standard offer service price." *Id.*

RUCO recommended that the standard offer generation rate for each class should be set at least as high as the expected retail market cost of generation service for that class, which it said is similar to Pennsylvania's. It gave two reasons for this approach. First, new entrants must overcome "the inertia and suspicions of customers who have been accustomed to buying their electricity from the same provider." *Id.* Second, it is not possible to predict future retail prices; neither the underlying wholesale prices nor retailing costs are known in advance. Thus, RUCO said at the beginning of competition it is better to have the standard offer generation be somewhat higher than the competitive retail price of power so more customers will switch. Even though this might result in lower revenues from Direct Access customers, RUCO recognized in September of 1998, that TEP is still protected by its CTC in the collection of any stranded costs. *Id.* at 10.

TEP's Average Generation Shopping Credit Should Be at Least 6.12 Cents

TEP's historic electric costs were unbundled by Dr. Rosen. He concluded that TEP's average generation cost was 6.12 cents per kWh, as set forth in Table 2 of Commonwealth Attachment No. 1. In order for competition to occur in TEP's service area, a year around average shopping credit of at least 6.12 cents per kWh should be reflected on all customer bills. This generation component represents over 70% of the customer's total electric bill.

TEP's Generation Assets Are Likely to Sell for More than Their Book Value

Certain generation assets are likely to sell for more than their book value. This was the conclusion reached by Mr. Kevin Higgins, the AECC consultant, when he reviewed the Proposed APS/TEP Settlement. He recommended that those proceeds be used to reduce the CTC. Direct Testimony of Kevin C. Higgins, *A.C.C. Docket Nos. E-01933A-98-0471 et seq.* (Nov. 30, 1998) at 15.

Conclusion

Based upon the previous testimony and all the evidence in these dockets, and the Direct Testimony of Frederick Bloom, Commonwealth respectfully urges the Commission to reject the Settlement in its entirety, or at a minimum, incorporate the recommendations of Commonwealth.

LIST OF WITNESSES

1. Frederick M. Bloom

SUBJECT AREAS OF THE DIRECT TESTIMONY OF FREDERICK M. BLOOM

1. Framework for electric competition under the TEP Settlement
2. Lack of benefits for residential and business customers under the General Services tariffs

3. Impediments to competition created by the TEP Settlement

4. Public interest will not be served by the TEP Settlement

5. Market generation credit and CTC charges

6. TEP's Adder

7. Full imbedded cost generation shopping credit

8. Credits for metering, meter reading and billing and collection services

9. Unbundling of TEP's rates

10. Divestiture of generation assets

11. Market power

12. Must-run units

13. Low-income assistance programs

14. Affiliate transaction rules and code of conduct

RESPECTFULLY submitted this 28th day of July, 1999.

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ORIGINAL and ten copies of the foregoing Notice and Testimony were filed this 28th day of July, 1999 to:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

COPIES of the foregoing Notice and Testimony were *hand-delivered* this 28th day of July, 1999 to:

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COPY singular of the foregoing Notice and Testimony were *air-expressed* this 28th day of July, 1999 to:

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Docket No. RE-00000C-94-0165 Service List

By ____________________

Analysis and Recommendations of Residential Utility Consumer Office Regarding the Tucson Electric Power Company's Stranded Cost Filing

Docket No. E-01933A-98-0471

Introduction

The Residential Utility Consumer Office (RUCO) is responding to the Tucson Electric Power Company's (TEP's) stranded cost "Application" of August 21, 1998. In this Application, TEP describes a possible process for auctioning its generating assets, although the Company proposes to "retain the ability to amend the auction procedures or protocols or suspend or terminate the auction" (p. 19). For those generating assets not sold, the Company requests that it nonetheless "be authorized to recover 100 percent of the Final Stranded Cost Amount associated with such asset(s)" (Exhibit A, p. 12, lines 2-3). TEP estimates that its stranded costs after the sale of its generating assets, in 2001, will be between $600 million and $1.1 billion (p. 20), "based on numerous assumptions" which are unspecified. Presumably, then, the Company's methodology would estimate even higher strandable costs beginning in 1999.

Until the divestiture process, successful or not, is complete, TEP proposes an interim competition transition charge (ICTC) to be paid by all customers. This charge would equal the difference between "the generation portion of each rate schedule" and the wholesale price of electricity at California's Palo Verde switchyard (Exhibit C).

After the divestiture process, the Company's stranded costs would be calculated again. For any generating assets sold, the stranded cost would equal the difference between net book value and sale price, plus the transportation costs associated with selling the assets. For any assets TEP decided not to sell, the strandable cost would be estimated using a "Net Lost Revenues approach" (p. 23). After divestiture, the ICTC would be replaced by a permanent competition transition surcharge (CTC) designed to recover the newly calculated strandable cost amount within ten years.

RUCO generally approves of the idea of divesting TEP's assets but finds many aspects of the Application and plan unacceptable. At present, the Application asks for approval of TEP's stranded cost recovery methodologies without fully revealing those methodologies. The methodology for calculating the ICTC is revealed, but the use of a wholesale, rather than a retail, market generation price to compute stranded costs on an interim basis, would leave no opportunity for alternative generation suppliers to offer power at lower prices than the standard offer. It would also lead to a significant over-estimation of stranded costs.

Also, TEP's divestiture plan would not require TEP to actually sell any units, but would nonetheless guarantee 100% recovery of estimated stranded costs. Furthermore, the plan seems to give the Company unrestricted power to manipulate the auction process and to eliminate or select bidders entirely at its own discretion. This could allow TEP to sell units to affiliates at bargain prices. In conjunction with TEP's distortion of the Commission's generous offer to let Affected Utilities keep 50% percent of negative stranded costs, this unrestricted power would also enable the Company to severely overcollect such a 50% reward at the expense of ratepayers, if stranded costs for some generating units were negative.

Finally, the Application would allow TEP to collect stranded costs on a fixed fee (per customer) basis, which would clearly be unfair to Arizonans who use little electricity. This approach would greatly increase their average electricity rates, and is, therefore, contrary to the Emergency Rules. Some of the Company's cash requirements would be financed through securitization, which in itself may be sensible. However, securitization should not be allowed for the stranded costs of any plants not divested, because securitization restricts the flexibility of the true-up process. Furthermore, the particulars of TEP's securitization plan, as written, may create opportunities for unregulated profit-skimming by TEP and its affiliates.

TEP's Stranded Cost Estimate

TEP's Application reports stranded costs of between $600 million and $1.1 billion, "based on numerous assumptions" (p. 20) which are neither explained nor revealed. In confidential Schedule 3 of the Company's Application, a table presents the estimates' basic components. A second table displays the assumed "value," per kilowatt, of each TEP generating plant. Just two sentences describe how the numbers in the tables were developed. After the second table, the following sentence appears: "This Application seeks approval for the proposed methodology of determining stranded costs, including the components set forth in the foregoing table."

Clearly, two tables and two sentences are not an adequate basis on which to judge the validity of a methodology for calculating stranded costs. RUCO recommends that no final methodology for calculating recoverable stranded costs on an interim basis or a final basis be approved unless it is thoroughly revealed and examined first in hearings. The ACC's Stranded Cost Working Group found in its September 30, 1997 report that "for purposes of the required stranded cost filings to be made by the Affected Utilities, they should bear a strong burden of proof as to the reasonableness of whatever estimation method they may incorporate into their respective filings" (p. 33). Thus, RUCO may supplement its comments later once the details of the proposed methodology become known through the discovery process, and can be analyzed.

In contrast to the mysterious methodology proffered by TEP, RUCO witness Dr. Richard Rosen's stranded cost methodology was explained at length in Dr. Rosen's January, 1998 testimony in ACC Docket No. RE-00000C-94-0165. Dr. Rosen estimated that the TEP's strandable generation costs at that time were $513.4 million dollars over the time period 1998-2020. However, beginning in 1998 they decline rapidly as TEP ratepayers continue to pay above-market generation rates as they have in the past. TEP's estimate is for the time beginning when the plants change hands, presumably at the beginning of 2001, through the life of the assets. Therefore, to make Dr. Rosen's estimate comparable to the TEP estimate, the over-market payments for the years 1998, 1999, and 2000 must be removed from Dr. Rosen's estimate. This is shown on page one of Attachment RUCO-1. The result is estimated positive stranded costs with a 1998 present value of just $84.1 million dollars.

Interim Competition Transition Charge

TEP describes its proposed Interim Competition Transition Charge (ICTC) on pages 21-22 of its Application:

> The ICTC will be in effect until such time as the CTC is implemented and will be charged to competitive customers and to Standard Offer customers as a component of the Standard Offer Rate. The ICTC will be the difference between the Standard Offer embedded cost of generation under traditional ratemaking and a market price for power. The market price of power will be based on the Dow Jones Palo Verde Index,...a measure of actual spot market prices....at Palo Verde Switchyard.

Theoretically, the ICTC would simply continue to collect the above-market values of generation assets at the same rate at which they would be collected under continued traditional ratemaking. However, a proper ICTC that is consistent with this objective must be calculated using retail generation prices rather than wholesale prices such as those at Palo Verde. The competition which TEP will face as a result of the Commission's competition rules is for retail generation sales within its own service area, not for spot market sales at the Palo Verde switchyard. Thus, the appropriate "market price for power" for computing stranded costs is the local retail market price, which will vary from class to class. This local retail market price for each class is also the appropriate standard offer generation rate for that class.

All ESPs offering retail generation service in TEP's service district will incur significant costs in addition to the wholesale cost of generation. In earlier testimony in Docket No. RE-00000C-94-0165, Dr. Richard Rosen estimated that these additional costs would range from 0.82 to 1.18 cents per kWh for service to small customers and from 0.54 to 0.85 cents per kWh for service to large customers. The largest component of these "retail adders" is the administrative and general costs of providing retail service. The remainder consists of associated customer services, marketing and advertising, ancillary services (not including those mentioned in FERC Order 888), profit, and taxes (Exhibit RAR-3). Dr. Rosen used an average retail adder of 0.77 cents per kWh in computing stranded costs, and in computing the price of Standard Offer Service.

If the standard offer generation rate is too low to allow alternative ESPs to cover the wholesale cost of generation plus their retailing expenses, then "full generation competition as soon as possible," one of the Commission's stated objectives in addressing the stranded cost issue (Decision 60977, p. 8), will not be accomplished. In fact, there will probably not be any retail competition, as is generally the case in California, Massachusetts and Rhode Island, which made this same mistake in using a wholesale price of generation to set the standard offer service price.

Thus, to encourage a competitive generation market, the standard offer generation rate for each class should be set at least as high as the expected retail market cost of generation service for that class. There are two reasons to set these rates towards the higher end of a reasonable retail market price range for each customer class, at least initially, as Pennsylvania has done. One is to overcome the inertia and suspicions of customers who have been accustomed to buying their electricity from the same provider. The second is that it will not be possible to predict the retail market prices with certainty.

Neither the underlying wholesale price of power nor the retailing costs are precisely known in advance. If the standard offer generation is somewhat higher than the competitive retail price of power, more customers will switch. At the beginning of retail competition, this is better than having few customers switch, which would be the consequence of a standard offer generation rate lower than the competitive retail price of power. Periodically, perhaps each year, the Commission can adjust the standard offer generation rate for each rate class so that it stays in reasonable relationship to the spread of retail prices in the market.

If the ICTC is the difference between the company's generation cost of service and the standard offer generation rate, then a higher generation rate would result in a lower ICTC. The consequence would be lower TEP revenues from direct access customers. This would not be a problem, as any stranded cost amount not collected through the ICTC would be collected through the CTC, duly adjusted for the Company's cost of capital. Thus, the actual level of the ICTC must be set in litigated hearings in a manner consistent with the way that the standard offer generation rate is set, so rates do not increase. However the ICTC is set, the total present value of stranded costs charged to ratepayers over the 10-year recovery period should not exceed the sum of the present values of the ICTC collected and the permanent CTC. Note also that according to Dr. Rosen's calculations, if an ICTC is set the way the Company proposes, there may be little in the way of stranded costs to collect later.

Auction

There are several problems with TEP's proposal for an auction of its generating assets. First, as the Application is written, the Company is not obligated to auction anything. "The Company will retain the ability to...suspend or terminate the auction, should it be in the best interest of the Company and its stakeholders" (p. 19).

Yet, for any generating assets it chooses not to sell, the Company states that it "must have a definitive alternative mechanism that provides full recovery of Stranded Costs" (p. 4). This mechanism would consist of estimating the stranded costs on the unsold units and adding that estimate to a "Stranded Cost Recovery Asset" to be recovered in its entirety through regulated cash flows (pp. 23-24). Such a sequence of events would not adhere to the Commission's statement that "the opportunity for full stranded cost recovery should be available only to those Affected Utilities that choose to divest" (Decision 60977, p. 10). However, if any portion of the strandable cost amount to be recovered from ratepayers is based on an administrative rather than a market determination, that portion should be trued up over time as actual market price information becomes available in place of the projections used in the first administrative strandable cost determination. A true-up is needed to protect ratepayers from overpaying stranded costs when an administrative determination of stranded costs is relied on.

The Application, in addition to giving the Company the ability to terminate the auction, would also grant the Company arbitrary power to select the winning bidders without regard to the merits of their bids, if the Company so choses. On page 4 of the Application's Exhibit B, "TEP reserves the right to at any time, in its sole discretion, to [sic] select which bidders to invite to Phase III, Phase IV or the bidder(s) with which to execute Documents, terminate discussions with any or all bidders, amend or otherwise change the protocols…." This provision, and others like it in the Application, might give TEP the opportunity to sell generating assets to an affiliate for a price lower than that which some competing bidder would make. This might contradict item R14-2-1617(A)(7)(b) of the Affiliate Transactions rules. That item states, "Goods and services…developed for sale on the open market by the Affected Utility or Utility Distribution Company will be provided to its affiliates and unaffiliated companies on a nondiscriminatory basis, except as otherwise permitted by these rules or applicable law."

The previous decisions of the Commission may make it more difficult for TEP to favor its affiliates, but they may not prevent it altogether. Page 12 of Decision No. 60977 stipulates that "no entity or its affiliate(s) may purchase generation assets at any divestiture auction unless it is the highest bidder…." However, if TEP eliminated some or all of the other bidders early in the auction process, then a TEP affiliate could end up offering the winning bid even if other capable parties had been prepared to offer more. If all other bidders were eliminated, then any bid would suffice, and the auction would be a sham.

R14-2-1617(A)(7)(a) is an important provision for preventing items from being sold by utilities to their affiliates at below-market prices. It states that in such a sale, "the transfer price will be the higher of fully allocated cost or the market price." This may prevent TEP from selling a plant to an affiliate for less than the fully allocated cost, but an appropriate "market price" might never be established if TEP eliminated other bidders at early stages or otherwise manipulated the auction process. As a result, TEP might be able to sell one or more generating units to one or more affiliates for bargain prices.

Incidentally, R14-2-1617(A)(7)(a) could also effectively prevent utility affiliates from bidding on any generating units whose fully allocated costs are higher than their market prices. The Commission should, perhaps, clarify the applicability of this provision to sales of generation assets, if it has not done so already.

In its Application the Company reserves for itself not only the rights to eliminate and select bidders at its sole discretion and to cancel the auction, but also "the ability to amend the auction procedures and protocols without ACC approval." This unfettered freedom to manipulate the auction process potentially enhances the Company's power to profit from divestiture at the expense of ratepayers, in ways not explicitly approved by the Commission.

Aside from the need to prevent abuses such as the ones described above, an additional reason for the Commission to retain supervisory control over TEP's auction process is that the process should be conducted in a manner that prevents undue market power from resulting. The issue of how to structure an auction in a way to mitigate the likelihood of undue market power requires considerable study, and TEP has not proposed a method for dealing with it. An auction process that takes no account of market power could result in market power that would significantly increase costs for Arizonans. The Commission must require TEP to devise an auction plan that explicitly minimizes market power by the purchasers of the plants. Part of doing this requires an analysis of whether Tucson is a load pocket, and, therefore, whether special market power mitigation provisions like price caps are required in the auction.

Incentive for Divestiture in Case of Negative Stranded Costs

Decision No. 60977 gives the utilities a considerable incentive to sell their power plants to non-affiliated entities for the highest possible prices: "An Affected Utility that divests all its generation costs to non-affiliated entities, that results in negative stranded costs (not including regulatory assets) as defined by the Commission's Retail Electric Competition Rules and this Order, shall be entitled to keep 50 percent of the negative stranded costs" (p. 12, lines 7-9).

The 50 percent reward concept is addressed in TEP's plan as well, but is significantly distorted. If the reward were calculated as TEP proposes, the Company could receive a substantial reward for *negative* stranded costs even if its net stranded cost amount were a considerable *positive* sum, as both the Company and Dr. Rosen estimate.

The Company seeks the following reward provision: "…to the extent that the final sale price of *any* [emphasis added] Asset exceeds the Company's net book value for such Asset, 50 percent of the gain on such Asset will be applied to reduce the Company's Stranded Costs" (Application, p. 22).

TEP's plan proposes, then, that the Company potentially receive the reward on each individual unit to be sold which has negative stranded costs, rather than on the net amount of stranded costs for all units together. This proposal would give the Company no incentive to maximize the sale prices of generating units that truly have market values lower than their net book values (i.e. units that truly have positive stranded costs), because the prices of those units would have no effect on the amount of the reward the Company would receive.

Worse, calculating an award on the basis of each individual unit's stranded costs would create a perverse incentive to prefer bids which offer a minimal price on one unit (or group of units) in exchange for a higher price on another unit (or group of units) in order to increase the negative stranded costs on those units which would be subject to the reward. These sorts of bids would maximize TEP's rewards even if they reduced the aggregate sale prices. Since TEP's plan also would grant the Company unchecked power to manipulate the auction process however it chose, the Company would have many tools for encouraging reward-maximizing bids. The bidders could easily figure out that if they paired a high bid on one power plant with a minimal bid on a another plant, they could gain TEP's favor while possibly saving themselves money. To the extent that the Company chose to sell its assets, the reward structure it proposes would tend to turn its power plant auction into a "buy one, get one free" sale. Therefore, TEP's plant-by-plant reward proposal must be totally rejected by the Commission. All components of stranded costs should be netted out against each other before any incentives are given.

Furthermore, TEP's plan would expand the rewards by excluding enormous positive stranded costs from the amounts on which the rewards would be based. This violates the Commission's instructions that any reward is to be based on "stranded costs" (implying total stranded costs), not on a narrow subset of these costs. As the first table in Schedule 3 shows, TEP's proposed methodology holds large and diverse stranded costs separate from this calculation. Aside from leading to much larger TEP rewards at the expense of ratepayers, this feature of TEP's plan would also remove any incentive for the Company to minimize these other stranded costs.

Moreover, by excluding many categories of stranded costs from the reward basis, TEP would give itself a perverse incentive to incur new costs that would not be included in the reward basis, but would increase the sale price of a generation asset. The Company could spend $500 million dollars in certain types of new stranded costs to increase the sale prices of the generation units by just $50 million, but still benefit because the higher sale prices would increase the reward while the stranded costs would be fully recovered and yet would not reduce the reward. In particular, RUCO is concerned that TEP may choose to pay high penalties for terminating leases on its generation assets (Application, p. 11) in order to increase their value at auction even if directly reassigning the leases to purchasers of the plants would be more cost-effective. The increased sale prices would add to TEP's reward, but the termination payments would not reduce the reward because they are a category of stranded cost not included in TEP's proposed basis for calculating the reward. Indeed, the Application indicates that "The Company's preferred alternative for disposition of its leasehold assets is to negotiate a termination of the leases" prior to the auction (p. 17) because "terminating the leases will result in a more streamlined auction and increase the number of potential purchasers" (p. 18).

Aside from lease termination payments, there may be other types of unjustified new stranded costs the Company would choose to incur under its perverse incentive scheme in order to increase the sale price of its generating assets. The stakes are extremely high, since "the total of the [payments required to complete the divestiture of TEP's assets] are likely to exceed the sale proceeds received for the Assets" (Application, p. 15).

Guaranteed 100% stranded cost recovery is generous. A 50% reward for net negative stranded costs is even more generous, all the more so when the "negative stranded cost" amount used for calculating the reward does not include regulatory assets, which are positive stranded costs. TEP appears to have taken this ACC incentive structure, to be funded by ratepayers, and distorted it into something that could cost the ratepayers even more, first by increasing the rewards to the company, then by potentially promoting wasteful decisions that add to overall positive stranded costs. To avoid these problems, any reward for TEP, or any other company, should be based on stranded costs in the aggregate, on a net basis.

For logical consistency, the purpose of calculating only reward, one of the items that must be included in the net, aggregate stranded cost amount is the present value of all ICTC payments received by TEP. They are part of the Company's stranded costs as of the advent of retail competition. If they are not included in the calculation, then stranded costs will be grossly underestimated, and an unjustified reward could result. The ICTC will rapidly reduce the lifetime strandable cost amount associated with TEP's generation assets, turning it negative in just a few years. Again, according to Dr. Rosen's estimates, the remaining stranded costs will already have approached zero as of January 1, 2001, TEP's scheduled date for transferring auctioned assets to new owners. If this projection understates the rate of decline of the lifetime stranded cost amount, or if there is any delay in the divestiture process, then the lifetime stranded cost amount on TEP's generation assets at that time could be negative. It would very rapidly become more negative with time. If the ICTC payments were not added back into the stranded cost calculation for the purpose of calculating the reward, then TEP would also have an incentive to try to delay the divestiture process. The later the transfer of assets, the larger the reward. This would result in a completely unjustified reward, potentially a large sum, that would come out of the pockets of ratepayers.

Finally, in TEP's adaptation of the reward concept, there is no mention of the Commission's conditions for reward eligibility: 1) the Affected Utility must "divest *all* [emphasis added] its generation costs," and 2) the purchasers must all be non-affiliated utilities (Decision 60977, p. 12).

Determination of Stranded Cost Amount to be Recovered from Ratepayers

If the Commission passes the order which TEP asks it to pass (Exhibit A of the Application), then "The Company's Final Stranded Cost Amount to be recovered shall be determined by the Company" (p. 6, lines 5-6). This is clearly unacceptable to RUCO. Furthermore, the "Charges shall be filed with the Commission and will be effective on filing" (p. 12, lines 26-27). RUCO is concerned that if TEP is given the unmitigated power to determine how much money it will collect from ratepayers, the Company may abuse the power. This approach must be rejected and any interim or final determination of stranded costs, whether through auction or through administrative calculation, must be reached in a litigated hearing.

Even requiring TEP to adhere to the stranded cost calculation methodologies it used to derive the estimates and examples in its Application would not be sufficient to prevent overcollection from ratepayers, in RUCO's opinion. These methodologies are not revealed in sufficient detail for their adequacy to be judged. The most important methodology is the one used to derive the estimates of TEP's overall stranded costs on page 20, and in Schedule 3. Yet, very little of this methodology is revealed in the Application, as noted in the summary above and the "TEP's Stranded Cost Estimate" section of this analysis. The ICTC calculation methodology described in Exhibit C of TEP's application is simple, but the "generation portion of each rate schedule" is presented without any indication of how each was derived, or what data it is based on. The methodology for estimating the strandable costs of any generating assets TEP chooses not to sell is not illustrated at all. It is merely described in general terms. The longest description is a few vague sentences on pages 23-24.

All of TEP's calculations of its stranded costs would seemingly depend on the Company's unbundling methodology for generation costs, which is most appropriately addressed in the ACC's unbundling proceedings. Thus, RUCO believes that the final stranded cost determination for TEP must await the ACC's final order on TEP's unbundling, and that this unbundling should include the development of the approved generation components of rates.

Method of Recovering Final Stranded Cost Amount

TEP's generation assets, with their corresponding negative or positive overall stranded cost, were built to meet the energy and capacity demands of ratepayers. Thus, any responsibility for paying stranded costs attributed to those ratepayers should be in proportion to their use of electricity. As such, any recovery of net positive stranded costs should be on a per-kWh basis, and possibly on a per-kW basis if appropriate, according to actual usage. Of course, per-kW recovery should apply only to customers whose peak demand is metered. Positive stranded costs should definitely not be recovered on a per-customer, one-fee-fits-all basis. Therefore, TEP's proposal that the CTC be recovered "on a per-kWh, a kW and/or a fixed fee basis" (Exhibit A, p. 6, line 30) should not be accepted. To accept TEP's approach would be completely inconsistent with the ACC's Emergency Rules whereby stranded costs must be recovered in a manner consistent with the way in which they are currently being charged in rates. TEP's fixed fee option must be excluded. It would clearly impact the lowest usage customers the hardest.

Requests for Waivers

RUCO opposes the granting of several of the waivers which TEP has requested. Specifically, RUCO objects to the waiver of condition numbers 19, 20, 21 and 28 in Decision No. 60480.

Conditions 19, 20 and 21 restrict TEP's actions in certain ways, for the purpose of improving TEP's debt-heavy capital structure. TEP requests a waiver of these conditions, claiming that its capital structure will be dramatically redefined after divestiture. While divestiture would likely improve TEP's capital structure, it is premature to waive these conditions at this time. After any Commission-authorized divestiture is completed, waiver of these conditions may be appropriate. However, it is premature to grant these waivers at this time.

Condition 28 prevents TEP's parent company and sister companies from investing amounts greater than $60 million in any single investment without Commission approval. This condition was also designed to protect TEP's customers from further deterioration of TEP's capital structure. The Commission may approve any such investment, but it is inappropriate to waive the condition in its entirety.

Conclusion

RUCO believes that the divestiture of generation assets by TEP could help promote a competitive market for retail generation services. However, there are many serious problems with the Company's proposed divestiture plan, as described above. These would give the Company unjustifiable opportunities for profiting at the expense of ratepayers, and these problems must be corrected before the relevant elements of TEP's Application are approved by the Commission.

Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.10	3.10	6,986	216.4
1998	2.65	2.65	7,122	188.5
1999	2.13	2.13	7,261	154.4
2000	1.53	1.53	7,403	113.3
2001	1.39	1.39	7,548	105.1
2002	1.25	1.25	7,695	96.4
2003	1.11	1.11	7,846	86.9
2004	0.96	0.96	7,999	76.6
2005	0.80	0.80	8,155	65.6
2006	0.65	0.65	8,315	53.7
2007	0.48	0.48	8,477	40.9
2008	0.31	0.31	8,643	27.2
2009	0.14	0.14	8,812	12.5
2010	(0.04)	(0.04)	8,984	(3.3)
2011	(0.22)	(0.22)	9,159	(20.2)
2012	(0.41)	(0.41)	9,338	(38.2)
2013	(0.60)	(0.60)	9,521	(57.5)
2014	(0.80)	(0.80)	9,707	(78.1)
2015	(1.01)	(1.01)	9,897	(100.0)
2016	(1.22)	(1.22)	10,090	(123.4)
2017	(1.44)	(1.44)	10,287	(148.3)
2018	(1.67)	(1.67)	10,488	(174.9)
2019	(1.90)	(1.90)	10,693	(203.1)
2020	(2.14)	(2.14)	10,902	(233.1)

Net Present Value of Stranded Costs (1998-2020) (1998$):	**$513.4**
Net Present Value of Stranded Costs (2001-2020) (1998$):	**$84.1**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (2001-2020) (1998$)	**$84.1**

Assumed utility nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.02	6.12	0.00
1998	3.47	6.12	0.00
1999	3.99	6.12	0.00
2000	4.59	6.12	0.00
2001	4.73	6.12	0.00
2002	4.87	6.12	0.00
2003	5.01	6.12	0.00
2004	5.16	6.12	0.00
2005	5.32	6.12	0.00
2006	5.48	6.12	0.00
2007	5.64	6.12	0.00
2008	5.81	6.12	0.00
2009	5.98	6.12	0.00
2010	6.16	6.12	0.00
2011	6.34	6.12	0.00
2012	6.53	6.12	0.00
2013	6.72	6.12	0.00
2014	6.93	6.12	0.00
2015	7.13	6.12	0.00
2016	7.34	6.12	0.00
2017	7.56	6.12	0.00
2018	7.79	6.12	0.00
2019	8.02	6.12	0.00
2020	8.26	6.12	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Tucson Electric Power Company
(thousand dollars)

Category	Total Cost	Cost Components: Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$339,092	$339,092			
O&M Minus Fuel	$135,991	$135,991			
Fuel	$203,102	$203,102			
Transmission	$6,894		$6,894		
Distribution	$12,284			$12,284	
Customer/Sales	$14,501				$14,501
Subtotal	$372,771	$339,092	$6,894	$12,284	$14,501
A&G[1]	$59,943	$48,044	$2,436	$4,340	$5,123
Total	$432,714	$387,136	$9,330	$16,624	$19,624
Plant Related Costs:					
Depreciation and Amort.	$76,229	$38,188	$17,533	$20,508	$0
Net Interest	$103,096	$49,431	$23,867	$29,799	$0
Net Income	$11,982	$5,745	$2,774	$3,463	$0
Income Taxes[2]	$9,892	$4,743	$2,290	$2,859	$0
Other Taxes[3]	$37,604	$18,030	$8,705	$10,869	$0
Residual[4]	$21,514	$10,315	$4,980	$6,218	$0
Total	$260,317	$126,452	$60,149	$73,716	$0
Total Operating Revenues[5]	$693,031	$513,588	$69,479	$90,341	$19,624
less Wholesale Revenues	($106,945)	($94,201)	($12,744)	$0	$0
Total Retail Revenues	$586,087	$419,387	$56,735	$90,341	$19,624
Total Retail Sales (MWH)	6,851,706				
Average Retail Rate (cents/kWh)	8.55	6.12	0.83	1.32	0.29

Footnotes:

1 A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 80.2%, 4.1%, 7.2%, and 8.5%.

2 Income Taxes include Federal Income Taxes, Other Incomes Taxes, Provision for Deferred Income Taxes (incl. credits).

3 Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

4 Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

5 Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: **10.88%**

Combined Cycle:	Total Costs:	1996 Real Levelized Costs
Capital Costs	383.0 $/kW	0.79 ¢/kWh
Fixed O&M	11.7 $/kW-yr	0.22 ¢/kWh
Variable O&M	0.20 mills/kWh	0.02 ¢/kWh
Fuel	1.97 ¢/kWh	1.71 ¢/kWh
	Sum of Levelized Costs:	*2.74 ¢/kWh*
	Levelized Capacity Costs:	*53.4 $/kW-yr*

Combustion Turbine:	Total Costs:	1996 Real Levelized Costs
Capital Costs	275.0 $/kW	29.47 ¢/kWh
Fixed O&M	9.4 $/kW-yr	9.26 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.13 ¢/kWh
	Sum of Levelized Costs:	*41.86 ¢/kWh*
	Levelized Capacity Costs:	*39.3 $/kW-yr*

Capacity Factor Crossover for CC/CT		11%
Percent of CC energy in Market Price		99.6%
Percent of CT energy in Market Price		0.4%
Average Price of CC/CT mix		**2.91 ¢/kWh**
T&D Line Loss Adjustment	10%	0.30 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
Adjusted Retail Market Price based on CC/CT mix		**4.08 ¢/kWh**
Year Excess Capacity Ends		**2000**

(2) Using Capacity Charge and Energy Charge:

Capacity Charge ($/kW-yr):	**NA**	
Energy Charge (¢/kWh):	**NA**	
Average Market Price for Electricity:		**none ¢/kWh**

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		**1.59 ¢/kWh**
T&D Line Loss Adjustment	10%	**0.17 ¢/kWh**
Order 888 Ancillary Services		**0.10 ¢/kWh**
Retailing A&G Adjustment		**0.50 ¢/kWh**
Other Retailing Costs Adjustment		**0.27 ¢/kWh**
User-Input Retail Market Price for Electricity		**2.63 ¢/kWh**

Table 4
Assumptions Used in Estimating Stranded Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):		User-Input			
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Source: Rosen testimony in ACC Docket No. U-0000-94-165, Exhibit_(RAR-6)

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6,500	Btu/kWh

Schnitzer, in Docket #16705, Direct Testimony on behalf of Texas OPUC, and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11,900	Btu/kWh

Tellus Institute, Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	57%
M[illegible]nnual Load (MW)	1619
Mi[illegible] Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1862
Cut-off point:	11.0%
Load at above Cut-off (MW)	1527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
Percentage of Energy Supplied by CTs	0.4%
Percentage of Energy Supplied by CCs	99.6%

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	855,793	261,591	594,202	1,062
Feb	763,804	224,230	539,574	1,043
Mar	806,714	236,376	570,338	961
Apr	836,467	249,242	587,225	1,255
May	920,007	212,419	707,588	1,410
Jun	992,763	213,336	779,427	1,519
Jul	1,144,033	262,289	881,744	1,619
Aug	1,131,929	276,469	855,460	1,608
Sep	1,012,034	307,068	704,966	1,369
Oct	1,032,968	378,436	654,532	1,355
Nov	942,033	383,554	558,479	987
Dec	994,999	373,905	621,094	1,102
TOTAL	11,433,544	3,378,915	8,054,629	1,619

Utility FERC Form 1 Data

Average Wholesale Market Price of Electricity Based	29.09	$/MWh
on CC/CT Method	2.91	c/kWh
T&D Line Loss Adjustment	0.30	c/kWh
Order 888 Ancillary Services	0.10	c/kWh
Retailing A&G Adjustment	0.50	c/kWh
Other Retailing Costs Adjstmt	0.27	c/kWh

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	2.63	c/kWh

CC-CT Market Price Worksheet for: Tucson Electric Power Company

Utility Load Data:

For each utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user.

Month	Total Monthly Energy (MWh) USER-INPUT	Monthly Non-Requirements Sales for Resale & Associated Losses (MWh) USER-INPUT	Net Energy (MWh)	Monthly Peak (MW) USER-INPUT	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
Jan	855,793	261,591	594,202	1,062			
Feb	763,804	224,230	539,574	1,043			
Mar	806,714	236,376	570,338	961	961	81%	781
Apr	836,467	249,242	587,225	1,255			
May	920,007	212,419	707,588	1,410			
Jun	992,763	213,336	779,427	1,519			
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Aug	1,131,929	276,469	855,460	1,608			
Sep	1,012,034	307,068	704,966	1,369			
Oct	1,032,968	378,436	654,532	1,355			
Nov	942,033	383,554	558,479	987			
Dec	994,999	373,905	621,094	1,102			
TOTAL	11,433,544	3,378,915	8,054,629	1,619	961	0.81	781

LOAD FACTOR	57%
Max. Annual Load (MW)	1,619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1,862
Cut-off point:	11%
Load at above Cut-off (MW)	1,527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
check	0

ratio between total energy under load curve and total monthly energy	0.92
Ratio of energy supplied by CTs	0.4%
Ratio of energy supplied by CCs	99.6%

CC

Capital Cost	41.67	$/kW times	1,527	MW	equals	63,624,506	dollars	$ 27.43 MWh
Fixed O&M	11.70	$/kW times	1,527	MW	equals	17,864,161	dollars	
Var O&M	0.20	mills/kWh times	8,020,614	MWh	equals	1,604,123	dollars	
Fuel	1.71	cents/kWh times	8,020,614	MWh	equals	136,950,332	dollars	

CT

Capital Cost	29.92	$/kW times	335	MW	equals	10,023,160	dollars	$ 418.61 MWh
Fixed O&M	9.40	$/kW times	335	MW	equals	3,148,987	dollars	
Var O&M	0.10	mills/kWh times	34,015	MWh	equals	3,401	dollars	
Fuel	3.13	cents/kWh times	34,015	MWh	equals	1,063,294	dollars	
					TOTAL	234,281,965	dollars	
					Tot Energy in real LDC	8,054,629	MWh	

OUTPUT

Average Market Price of Electricity - 1996

29.09	$/MWh
2.91	c/kWh

BEFORE THE

ARIZONA CORPORATION COMMISSION

TESTIMONY OF FREDERICK M. BLOOM

On behalf of

Commonwealth Energy Corporation

Docket No. E-01933A-98-0471
Docket No. E-01933A-97-0772
Docket No. RE-00000C-94-0165

July 28, 1999

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DIRECT TESTIMONY

OF

FREDERICK M. BLOOM

(Docket Nos. E-01933A-98-0471, et al.)

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Frederick Bloom and my business address is 15901 Red Hill Avenue, Suite 100, Tustin, California 92780.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Chairman of the Board and Chief Executive Officer of Commonwealth Energy Corporation ("Commonwealth"). In 1997, I co-founded Commonwealth, which serves about 60,000 residential, small business, commercial and industrial and government customers in California. We are actively pursuing retail electric customers in other states, including Arizona.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I wish to provide my observations and concerns about this Proposed Settlement Agreement ("the Settlement") proposed by Tucson Electric Power Company ("TEP") and some selected parties. As I previously testified to in the Proposed Settlement Agreement involving the Arizona Public Service Company, I believe that I provide a unique perspective of a competitive electric marketer that is not affiliated with a regulated utility. I will address the necessary components of a competitive electric environment in the context of the TEP Settlement. I will then explain why the Settlement is not in the public interest, unless significant changes are made to that Settlement. I will then address the specific aspects of the Settlement, followed by my recommendations. Commonwealth also filed Comments on the TEP Settlement which are in the Notice of my Direct Testimony filing.

II. NECESSARY COMPONENTS OF A COMPETITIVE ELECTRIC ENVIRONMENT

Q. BASED UPON YOUR EXPERIENCE AS AN ELECTRIC SERVICE PROVIDER, WHAT IS NEEDED FOR A COMPETITIVE RETAIL MARKET IN ARIZONA?

A. Previously, I've testified before the Arizona Corporation Commission on the proposed Electric Competition Rules and before the Commission's Hearing Officer on the APS Proposed Settlement. Without restating Commonwealth's position, I would merely incorporate by reference Commonwealth's previous comments in the Electric Competition Rules docket and my direct and oral testimony and comments Commonwealth made in the APS Proposed Settlement case (ACC Docket Nos. E-01345A-98-0473 *et. seq.*). For convenience, I will summarize what is needed for a competitive retail electric market in Arizona by merely listing these important components:

- All customers of all classes should be entitled to choose their electric service provider.
- Customers should have an easy process by which to select alternative providers, such as through the third-party oral verification procedure we outlined in our comments on the Electric Competition Rules.
- All utilities, in this case TEP, should unbundle their cost of service so that it reflects the actual cost of providing that service by the utility.
- All customers should know what they are paying for, including how much of their bill is going towards stranded costs in the form of the "competitive transition charge" ("CTC").
- Uniform and stringent affiliate rules must be in place so that the utility can not discriminate or engage in market abuses.

These are the primary features of the competitive electric model if Arizona is truly serious about opening up competition for retail consumers.

Q. HOW DO THE ARIZONA ELECTRIC COMPETITION RULES RELATE TO THIS TEP SETTLEMENT?

A. Both the Arizona Electric Competition Rules and the TEP Settlement create the "rules of the road" to electric competition. They are interrelated, even though TEP and the other utilities want "many bites of the apple" in creating barriers for new entrants. They are proposing settlements, and at the same time they are requesting changes in the Electric Competition Rules so that they will not have to unbundle their tariffs to reflect the true cost of service consumers are paying under the Standard Offer and the Direct Access tariffs. If those costs are not the same "across the board," I believe it is discriminatory pricing and anticompetitive.

Q. DID COMMONWEALTH OR ANY OTHER COMPETITOR PARTICIPATE IN THIS SETTLEMENT?

A. Commonwealth was not a participant in this Settlement negotiations, nor was Commonwealth asked to participate. As far as I know, no competitor or electric service provider was given an opportunity to review and make any changes to the Settlement, so that competition might occur in the TEP service area.

III. OVERVIEW OF THE SETTLEMENT

Q. WHAT IS YOUR BUSINESS OPINION OF THIS TEP SETTLEMENT?

A. TEP serves about half the load as compared to APS or the Salt River Project ("SRP"). TEP has about 300,000 residential customers and about 30,000 general service business customers, with about the same amount of energy used by both classes. This TEP Settlement will impact all electric consumers within the TEP service area and economic development in southern Arizona, and perhaps the entire state. Even though TEP is not as large as APS or SRP, it will affect the economies of scale for any new entrant, particularly Commonwealth because we intend to serve all customers, including residential consumers.

Q. WOULD YOU BE ABLE TO PROVIDE COMPETITIVE ELECTRIC SERVICES IN TEP'S SERVICE AREA?

A. From my review of this Settlement and TEP's data responses, Commonwealth would not be able to provide competitive electric services in TEP's service area for several reasons. First, TEP severely limits the number of residential customers that could receive competitive generation. The start up costs and marketing to a limited number of potential customers is very expensive and involves high risk, particularly since all electric service providers ("ESP's") must compete for those limited consumers. Second, the metering requirements drive up costs but at the same time TEP does not offer an adequate credit in which to provide that metering service. Third, TEP is proposing to adopt a market generation credit ("MGC") which is tied to the CTC, which is in essence similar to the failed mechanism used in California which is used to calculate the recovery of stranded cost. As is well known, no serious competition is occurring in California, at least until the CTC charges expire. Fourth, the so-called "Adder" is inadequate. This nominal Adder is proposed to fix the 100 percent load factor TEP uses in setting the wholesale price. It does not begin to cover the retail business costs which a new provider must incur (or the retail-related generation costs TEP's Standard Offer customers pay). Fifth, without uniform and stringent affiliate transaction rules throughout Arizona, new entrants will lack assurances that no special treatment between the utility and the affiliate or other market abuses might not occur. With each utility drafting its own code of conduct, it creates confusion as to which utility can engage in certain activities under various circumstances and how the conduct will be monitored by the Commission.

Q. WILL RESIDENTIAL AND SMALL BUSINESS CUSTOMERS BENEFIT FROM THIS TEP SETTLEMENT?

A. Residential and small business customers will not achieve the retail electric competition they deserve under the Electric Competition Rules or the laws and policies of Arizona. Therefore, I believe residential and small business customers will not receive the benefits they are entitled to under this Settlement. Residential and small business customers would receive much more benefits from retail open competition if TEP is required to give a market generation credit equal to the cost of its own generation. Residential and general service customers (approximately 330,000) use over two-thirds of the energy sold by TEP. The 1% rate decrease is a token concession as compared to the savings that those customers could receive from the true sale of competitive generation. This Settlement would lock TEP's customers to the Standard Offer because I don't believe any alternative provider could compete. The very definition of TEP's "market generation credit" is tied only to the <u>wholesale</u> market price of that generation. There is no "headroom" to cover the competitor's startup costs or retail marketing costs. In essence, TEP's definition of MGC is the exclusion of competition.

Q. ARE THERE OTHER ASPECTS OF THIS SETTLEMENT WHICH DENY RESIDENTIAL AND SMALL CUSTOMERS THE BENEFITS OF COMPETITION?

A. Yes, the Settlement limits residential customer access. TEP would only allow the first 5% or 14,800 customers to seek an alternative provider. TEP claims this restriction is in the Electric Competition Rules and the Settlement merely recognizes that constraint. However, TEP was unable to point to any state (or utility) where this 5% limit has resulted in robust electric competition, in response to Commonwealth's data request. As I've testified to before, the Rules and the Settlement are intertwined. The Arizona utilities impose some barriers in the Rules and they seek more barriers in their settlements.

Q. WHY IS FULL CUSTOMER ACCESS IMPORTANT FOR NEW ENTRANTS?

A. Access to all customers, residential, small and large business, and others, is vital to the marketing plans of any new entrant who desires to enter a market which is initially 100% served by a competitor. The investment in advertizing, personnel, overhead and other start-up costs are extensive. In order to make that investment, Commonwealth would have to disperse that cost over as many potential customers as possible. If an artificial constraint, such as a 5% limit, is imposed, the ability to recoup that investment is significantly impaired, not to mention the short-term losses any new entrant would expect to occur until it develops a profitable market base. That is why I have consistently advocated for full open access for all customers is the only way for true retail electric competition to occur.

Q. **DO YOU BELIEVE THE SETTLEMENT PROVIDES FOR THE TIMELY IMPLEMENTATION OF ELECTRIC COMPETITION, AS STATED IN THE SETTLEMENT?**

A. No, I do not believe the Settlement will provide for the timely implementation of electric competition in TEP's service area, as stated in paragraph F, on page 2 of the Settlement. The Settling Parties "believe that competition in the electric industry will benefit all customers in providing greater efficiencies and lower electric power costs." I agree with that statement. However, the Settlement does not accomplish that for the reasons I describe in this testimony.

Q. **WILL THIS SETTLEMENT BE IN THE PUBLIC INTEREST?**

A. I do not believe this Settlement will be in the public interest because it will not promote electric competition. In fact, if this Settlement is approved it will likely keep competition from occurring until 2009, almost a decade after California has engaged in robust electric competition. Businesses in California will likely be able to operate at lower cost than those in Tucson. TEP has not determined what the average savings might be for its customers, according to its response to our data request. I can only conclude that this Settlement merely gives TEP continued monopoly control in exchange for a 2% rate cut for its customers. Furthermore, TEP claims it has not conducted any study on this rate reduction, the projected savings to TEP's customers, or the number of customers that are presumed to purchase competitive electric services under the Settlement. Therefore, I believe that no one can claim that it will benefit consumers.

IV. THE MARKET GENERATION CREDIT AND CTC CHARGES WILL CLOSE THE TEP SERVICE AREA TO COMPETITION

Q. HOW MUCH STRANDED COST IS TEP CLAIMING?

A. TEP is seeking $450 million which is designed to recover approximately $200 million of generation-related regulatory assets and $250 million in what TEP refers to as "above-market generation costs." Even though TEP claims $200 million in generation-related regulatory assets, it was unable to tell us how much of those regulatory assets have already been recovered, in response to Commonwealth's data request. TEP is also claiming a 10.67% rate of return on its unamortized balance of stranded costs through its Fixed CTC.

Q. HOW DID TEP CALCULATE THE ABOVE-MARKET GENERATION COST?

A. I don't know how or what market assumptions were used by TEP in calculating its generation-related stranded cost. TEP claimed its study is confidential and proprietary information in response to Commonwealth's data request. TEP only said it used "a fair value test" as prescribed in Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of* (FAS 121"), which uses a discounted future cash flow methodology. Depending on future generation market prices and other assumptions, TEP might be overstating its claim to stranded cost.

Q. WHY DO YOU THINK THE CTC FRAMEWORK WILL DISCOURAGE, IF NOT PROHIBIT, OTHERS FROM PROVIDING GENERATION COMPETITIVELY?

A. TEP is proposing a complex formula for calculating the CTC, even more so than that used in California. It is tied to the wholesale generation market. It is adjusted based upon allocation factors from the California wholesale market, which will not likely match the TEP customer's actual power usage. The CTC is split into variable and fixed components, both of which are hard to understand. Consequently, I don't know how any expert, not to mention how any customer, could figure out the appropriate CTC and the appropriate market generation credit, in deciding whether to switch providers. In fact, I'm not aware of any state or utility that has such a complex MGC and CTC, and apparently TEP is unaware of any similar use of this MGC or CTC, according to its data response.

Q. WHAT IS YOUR UNDERSTANDING OF THE FLOATING CTC PROPOSED BY TEP?

A. According to TEP's response to data request, the Floating CTC represents the costs of TEP's coal-fired generation that cannot be recovered either through the Fixed CTC or through competitive market energy sales. TEP claims the Floating CTC will vary depending on the size of the market generation credit during the rate freeze. In other words, TEP is guaranteed a market-based return on its coal-fired generation even though it may not be the most efficient operator. This Fixed and Floating CTC would guarantee TEP a revenue stream it could transfer within divestiture of that generation plant. All other suppliers of generation must operate efficiently in order to meet market prices. The Fixed and Floating CTC does not require TEP or its subsequent buyer to operate that plant efficiently.

Q. WILL IT BE COSTLY FOR TEP AND ESPs TO IMPLEMENT AND ADJUST THE FLOATING CTC?

A. Yes, the overhead and operational costs for both TEP and ESPs will be considerable. Despite Commonwealth's data request, TEP had no idea of those costs. I can assure you that the cost for ESPs would be extensive, because we would have to make forecasts of that Floating CTC and even then Commonwealth could not assure potential customers of potential savings. But as I've said before, Commonwealth would not even get to that point because the MGC and Adder framework does not even come close to creating a competitive market, even before one adds on the CTC charges.

Q. WHAT HAPPENS IF THE FLOATING CTC RECOVERS MORE THAN THE MARKET VALUE OF GENERATION FROM TEP'S COAL-FIRED PLANT?

A. Under the Settlement, TEP could still recover the Floating CTC through the year 2008. TEP claims the over collection would be credited back to the customers. This is a way in which TEP can borrow from its captive customers. Furthermore, it adds another layer of confusion for consumers. In other words, a competitor would have to explain to the consumer that TEP would be giving back some of the extra CTC surcharges which should be credited towards competitive generation that an alternative supplier is trying to market to the consumer. It is likely that no expert could adequately explain this concept. Busy consumers are even less likely to understand what savings might actually result. In addition, this complex framework would make it virtually impossible for alternative suppliers to market electricity on the basis of unknown and "potential" savings to customers.

Q. DOES TEP EXPECT THE SAME GROWTH RATE IN THE FUTURE AS IT DID IN THE PAST?

A. No. In the Settlement, TEP uses a compound average annual growth of 1.89% for the period 2000-2008. In contrast, the average annual compound growth rate of energy sales by TEP was 2.89% during the period of 1990-1998. TEP claims that this would result in the sooner recovery of the Fixed CTC. However, the <u>Floating</u> CTC will continue to stay in place until December 31, 2008. This seems to indicate that TEP is trying to over recover its stranded costs and discourage competitors from entering its market.

Q. DO YOU HAVE OTHER PROBLEMS WITH THE MGC PROPOSED BY TEP?

A. Yes, the MGC approach used by TEP makes it extremely difficult for consumers and competitors to determine if there will be any future savings, for other reasons. For instance, TEP will change the MGC calculation during each <u>quarter</u> using the Palo Verde NYMEX future prices. However, the Floating CTC will change <u>monthly</u> for each customer. Because of the uncertainty in that future price and monthly CTC, no customer is likely to change from TEP's Standard Offer. Furthermore, TEP proposes using a 100% load factor for serving a customer even though it recognizes that customers do not use the same amount of power for

24 hours a day 365 days in the year. TEP proposes to resolve this huge disparity in the use of the wholesale price by including the "Adder." This does not resolve the problem for several reasons. First, the Adder is totally insufficient to address the adjustment in the actual load factor, which for instance is assumed to be a 50% load factor for residential customers. Furthermore, the Adder does not address the additional costs associated with retail delivery of electricity. It merely is a partial attempt to address the load factor. Clearly, the Adder is insufficient to create a retail electric market.

Q. DO YOU HAVE OTHER CONCERNS ABOUT TEP's ADDER?

A. Yes, the Adder proposed by TEP was criticized by Dr. Richard Rosen when he analyzed the proposed APS and TEP settlement agreement last November. Dr. Rosen testified that the retail Adders in Arizona should be 82 to 118 mills per kWh for small customers, such as residential and small business consumers, and 64 to 85 mills per kWh for large customers, such as industrial consumers. In contrast, the Settlement has an Adder for residential and small customers of only 3.2 to 5.2 mills, based upon a complex formula. For large customers (over 200 kW), the Settlement only has an Adder ranging from 2.5 to 3.3 mills. Dr. Rosen urged that the Commission start with the upper ranges of the Adders he proposed because they were conservatively estimated and it would help facilitate competition. Even though the Residential Utility Consumer Office ("RUCO") attempts to disavow the professional work of Dr. Rosen during the Generic Stranded Cost proceeding, Dr. Rosen reaffirmed his expert opinion during his Direct Testimony in the subsequent proceeding on the proposed APS and TEP settlement agreement. A copy of Dr. Rosen's Direct Testimony of November 30, 1998 is attached to my Direct Testimony as FB-1.

Q. WHAT IS THE SETTLING PARTIES EXPLANATION OF THE ADDER?

A. The Settling Parties have conflicting interpretations of the Adder. Mr. Kevin Higgins, the consultant for AECC, describes the Adder as the "conversion of the wholesale-based MGC into a retail product," by referring to sections 2.1(c) and (d) of the Agreement, in his Direct

Testimony on page 5. Mr. Higgins says this Adder represents the margin available to Electric Service Providers in order to provide savings opportunities to competitive customers. TEP, on the other hand, claims this Adder is merely for adjustment of the 100% wholesale load factor of the NYMEX price to reflect the fact that no one uses power 24 hours of every day. I believe the Settlement is misleading when it is represented that the Adder is the conversion of the wholesale NYMEX to a "retail product." Furthermore, I believe Mr. Higgins is mistaken if he believes that this nominal Adder will result in any savings to competitive customers.

Q. WHY IS THERE SUCH A DISCREPANCY BETWEEN THE ADDER PROPOSED BY TEP AND THAT RECOMMENDED BY DR. ROSEN?

A. Dr. Rosen testified that when a market generation credit approximates the wholesale price of generation, retail competitors would be unable to match this wholesale price. He said the experience in Massachusetts, New Hampshire, Rhode Island and California amply demonstrate that if the MGC approximates the wholesale price, little or no competition results. From my experience in California, I concur with Dr. Rosen's opinion. Dr. Rosen testified that no retail costs have been included in the Adders, not even the retailing costs (generation-related G&A) that are currently within the utility's rates. He concluded by saying that the MGC for each customer class should be at least as high as the full retail market price of generation service for each class. I strongly agree with Dr. Rosen's expert opinion.

Q. WHAT MUST AN ESP KNOW ABOUT THE CUSTOMER'S POWER USAGE BEFORE THE ESP CAN FIGURE OUT THE APPROPRIATE ADDER?

A. TEP is proposing different Adders for different customers. In response to Commonwealth's data request, TEP said that the ESP must know the ratio of a customer's maximum summer monthly usage to its maximum winter monthly usage. From that ratio, then the ESP must figure out the appropriate Adder from TEP's Rider No. 1. For each customer, the ESP must perform a historic power use history. This, of course, drives up the transaction costs and would take considerable time and involvement of the customer as well as the ESP and TEP. In reality, few if any customers would be willing to take the time to collect their past year's power bills and send them to the ESP. The data collection through TEP would be costly and then require further analysis before any proposal could be submitted to the customer. In a nutshell, the transaction costs outweigh any potential savings. Consequently, no choice is likely and thus no competition would occur, except perhaps for a large customer who has hired a consultant or has an energy expert on staff.

Q. HAS TEP CONDUCTED ANY STUDY OF THE APPROPRIATE LEVEL OF A <u>RETAIL</u> ADDER?

A. No, TEP has not conducted any study on the appropriate level of a <u>retail</u> Adder which would assure a viable competitive option for customers and ESPs.

Q. WILL THE POSSIBLE CHANGES TO THE ADDER IN 2005 RESOLVE COMMONWEALTH'S CONCERNS?

A. Even though the Settlement says the Settling Parties might negotiate changes in the Adder in the year 2005, it does not address the <u>retail</u> marketing aspects of using the wholesale NYMEX price. TEP said, in response to Commonwealth's data request, that those change factors might address changes in load shape of a rate class, changes in relative prices for power between on-peak and off-peak periods, and changes in total prices of on-peak and off-peak power. All of those factors relate to load shaping from the use of a 100% load factor <u>wholesale</u> price to a "wholesale" retail shape, not any cost of retail service.

Q. WITH THE USE OF COMPUTERS AND THE LATEST TECHNOLOGY, COULD COMMONWEALTH SET UP A SYSTEM FOR COMPUTING THE SHOPPING CREDIT AND CTC?

A. Computing the MGC and the Adder, along with the Fixed and Floating CTC, would require an expensive investment in technical, personnel and computer generated numbers even before one could prepare a calculated "guess" as to what an alternative provider might offer a particular customer. From everything I've seen thus far, it would be very complex, very costly, and the start up costs in an effort to derive one number for each customer who may consider switching would be cost prohibitive for new entrants. This is a problem on top of the inadequate MGC and Adder.

Q. ARE YOU ALONE IN NOT UNDERSTANDING THE COMPLEXITY OF THIS MGC?

A. No. Commonwealth requested TEP to provide an illustration as to how the MGC would be calculated in advance, by describing each step, the source of information, and the computation. TEP responded by saying it did not have an example and referred Commonwealth back to the Settlement language.

Q. WOULD COMMONWEALTH BE ABLE TO COMPETE AGAINST TEP'S STANDARD OFFER?

A. No, Commonwealth would not be able to offer generation services in competition with TEP's Standard Offer. TEP essentially concurs, because it said that competitors would have to purchase generation at "below market price" in order to compete. The framework of the Settlement is not to allow competitors to "beat" the Standard Offer. The MGC and Adder are structured so that competitors must buy generation significantly below market price. That "below market price" must also be sufficiently low enough to cover all "wholesale to retail" market costs, the Fixed and Floating CTC, the added charges for must-run units, and other costs. In an open competitive market, no ESP would be able to buy at below market price. If a supplier sells below market price, it would also open the door on predatory pricing.

Q. HOW MUCH SHOULD THE GENERATION SHOPPING CREDIT BE?

A. According to the data response from TEP, the combined distribution (including distribution, meter service, meter reading services, billing and collection, demand-side management system benefits, customer information and life-line discounts system benefits, and uncollectible accounts) and transmission (T&D) component of TEP's Standard Offer rate averages 2.6

cents per kWh. The balance of course should be the generation shopping credit. For example, if a customer is paying 9 cents per kWh for the bundled Standard Offer service, the direct access customer should receive a generation shopping credit of 6.4 cents kWh.

Q. HAS THE MAGNITUDE OF THE TEP GENERATION SHOPPING CREDIT BEEN STUDIED BEFORE?

A. Yes. I believe TEP's customers should have a generation shopping credit equal to the cost of generation they are presently paying under their Standard Offer (present) rates. TEP, in its Stranded Cost Recovery Application, stated that the generation portion of its Standard Offer was 6.22 cents per kWh for its residential customers, 7.94 cents for its general service (or commercial) customers, and 6 cents per kWh for large general service (or industrial) customers. Approximately two-thirds of the customer's bill is for generation and the remaining one-third is for transmission & distribution ("T&D"), which is consistent with what we found out in the APS Settlement proceeding even though APS reverses that ratio in its Direct Access tariffs. RUCO also hired Dr. Richard Rosen to analyze the unbundled costs of the utilities, as I mentioned before. Dr. Rosen, calculated the estimated unbundled generation, transmission, distribution and customer revenue results for TEP in 1998, as follows:

Generation	6.12 cents per kWh
Transmission	0.83 cents per kWh
Distribution	1.32 cents per kWh
Customer-related expense	0.29 cents per kWh

Direct Testimony of Dr. Richard Rosen, dated January 21, 1997 (sic - 1998), at 40 & Exh. RAR-12, *Arizona Corporation Commission, Docket No. U-0000-94-165.*

In response to Commonwealth's data request, TEP said it has not performed any analysis on the comparability of Dr. Rosen's figures to those in this Settlement. I have attached the relevant excerpts of Dr. Rosen's testimony as FB-2 to my testimony.

Q. HAS RUCO CONDUCTED ANY STUDY OF THIS SETTLEMENT?

A. According to the response to our data request, RUCO has not performed any study on the savings or other benefits that might be derived from this Settlement. RUCO says it has not performed any study on the Settlement's ability to promote electric competition, on the expected generation shopping credits, or the similarity or inconsistency of charges to Standard Offer and Direct Access customers. RUCO also said it has not performed any study of cost-shifting associated with the same service that a customer receives under the Standard Offer or from an ESP.

Q. WILL CUSTOMERS PAY MORE STRANDED COSTS AND A HIGHER CTC WITH A MARKET GENERATION CREDIT BASED UPON TEP'S EMBEDDED GENERATION COST?

A. No, the TEP Settlement sets forth the total amount of the stranded costs and from that amount the CTC may be computed for the appropriate duration. TEP is proposing to structure the CTC mechanism so that it fluctuates based upon the wholesale generation price and therefore it will be able to keep customers on its Standard Offer. It is a mechanism to keep out competitors similar to the technique used in California. If the Commission required TEP to give its customers a shopping credit equal to TEP's cost of generation, then the customers would benefit under the Settlement.

Q. HOW WILL TEP BE SURE IT IS NOT OVER COLLECTING STRANDED COSTS?

A. The Settlement is silent as to how TEP will disclose the amount of stranded costs that it is recovering from its Standard Offer customers. TEP does not have any accounting system in which its stranded costs are pooled so that the Commission and others may know the total dollars that TEP is recovering.

Q. SHOULD THE CTC BE INCLUDED IN THE STANDARD OFFER UNBUNDLED RATE?

A. Of course, the CTC should be collected from all customers, including those that purchase electricity from TEP under the Standard Offer and those that purchase competitive electric service under the direct access tariffs. The problem I see is that the CTC is not reflected as a separate line item under the Standard Offer. Customers should know how much CTC they are paying in respective of their chose of generation provider.

V. METERING, METER READING AND BILLING & COLLECTION SERVICES CREDITS SHOULD BE BASED ON FULL AVERAGE COST

Q. WOULD COMMONWEALTH BE ABLE TO PROVIDE METERING, METER READING AND BILLING AND COLLECTION SERVICES UNDER THE CREDITS PROVIDED FOR BY TEP IN THE SETTLEMENT?

A. As I testified to in the APS Settlement, the Arizona utilities are on a mission to use the "net avoided cost" approach to metering, meter reading and billing and collection services. This methodology of course allows the utility to continue providing those services because all new entrants must incur the full cost of doing so.

Q. WHY DO YOU THINK THAT TEP AND THE OTHER ARIZONA UTILITIES WOULD LIKE TO KEEP CONTROL OVER METERING, METER READING, AND BILLING AND COLLECTION SERVICES?

A. Metering, meter reading, and billing and collection services allow TEP and the other incumbent utilities to maintain contact with the customers. TEP and the other utilities claim that the use of net avoided costs allow them to avoid the risk of incurring stranded costs associated with those services. In reality, I believe TEP does not want to lose contact with customers and it knows that if it had to compete on a full cost basis other metering, meter reading and billing and collection providers would likely lower those costs to consumers and make it more attractive for new entrants to enter the TEP service area.

Q. WHAT IS THE DIFFERENCE BETWEEN THE "NET AVOIDED COST" AND YOUR REFERENCE TO THE "FULL COST" OF PROVIDING THOSE SERVICES?

A. As Commonwealth has learned in the APS Settlement proceedings, the Arizona utilities only want to give a credit for the last marginal or decremental cost of providing that service. The utilities claim that this is the savings they experience based upon their short-run marginal costs. By using the short-run marginal costs, the utilities will maintain their monopoly hold on customers.

Q. PLEASE EXPLAIN HOW TEP WILL HOLD ON TO ITS MONOPOLY SERVICE BY USING SHORT-RUN MARGINAL COSTS.

A. As a provider in a competitive world, I must consider all of my costs and address both the short-run and the long-run. My understanding of the short-run is that some costs remain fixed over a certain period of time. The utilities claim they should always continue to recover those fixed costs, such as the same number of employees, the same General & Administrative ("G&A") expenses, the same office size, and the same general operational costs. In the long-run, all costs are considered variable. As an entrepreneur, I must be efficient to survive. I must consider both the short-run and long-run. The utilities, on the other hand, are reticent to making long-run types of changes, such as leasing facilities rather than buying, or reassigning or terminating personnel. The utilities continue to look at these expenditures as sunk or "fixed" costs. With more sunk costs, they can continue to get their regulated rate of return on those fixed costs, either through higher Distribution Charges or more stranded costs. The Commission should urge the utilities to be more efficient by requiring them to use long term marginal costs, which would be the same as the "average" full cost, in setting credits for metering, meter reading and billing and collection.

Q. SHOULD TEP BE ABLE TO RECOVER ITS CUSTOMER BAD DEBTS FROM CUSTOMERS WHO SEEK COMPETITIVE SERVICES?

A. No. TEP should not be able to charge Direct Access customers for the "uncollectible accounts"it incurs in providing Standard Offer and Direct Access services. Even though TEP claims it has allocated some of those bad debt charges to generation, TEP should be encouraged to operate efficiently in seeking adequate deposits and other assurances of payment. By placing higher charges on Direct Access customers for those uncollectible accounts, it will discourage those consumers from seeking an alternative provider. Furthermore, alternative providers have a much higher risk of uncollectible accounts. As I previously testified, the Electric Competition Rules do not provide for an adequate deposit and ESPs do not have the ability to terminate services, as does the utility. This bad debt cost transfer to Direct Access customers of ESPs further compounds this problem.

VI. UNBUNDLING OF RATES IS A NECESSITY

Q. HAS TEP PROPERLY ALLOCATED ITS COSTS AMONG TRANSMISSION, GENERATION AND DISTRIBUTION?

A. TEP uses a different method that did APS. Therefore, it is difficult to know whether or not either method is appropriate or perhaps neither. Clearly, the utility should not be given carte blanc flexibility on how it wants to shift costs among transmission, generation and distribution. As I've testified to before, the monopoly utility, including TEP has the incentive to shift as much of their generation costs over into the regulated distribution side. I'm not aware of any analysis that would lead me to believe that these rates for direct access service are just and reasonable.

Q. WHAT IS YOUR GENERAL IMPRESSION OF TEP'S COST OF SERVICE?

A. TEP is relying on a five-year old cost of service study. During that period of time, its growth rate has been 15.25%. With this large increase in sales volume, one would naturally expect that the cost of service would have declined significantly. Consequently, it is reasonable to assume that these direct access charges are too high.

Q. ARE THERE OTHER IMPLICATIONS FROM THIS LARGE GROWTH AND RELIANCE ON THE 1994 COST OF SERVICE STUDY?

A. Yes, the rising power consumption essentially means that TEP is likely recovering for its shareholders a higher rate of return than initially authorized when that study was performed.

Q. HOW SHOULD TEP UNBUNDLE ITS SERVICES?

A. Both competitive and non-competitive services, as outlined in the Arizona Electric Competition Rules, should be unbundled so that customers know what they are paying for. Both customers and competitors would have the same price signals. In addition, it is the only framework in which the Commission would be sure that the Standard Offer and Direct Access tariffs are just and reasonable. The Commission needs to know how much TEP is charging for its regulated components of both the Standard Offer and Direct Access tariffs in administering its obligations under the Arizona laws. For illustration purposes, I prepared the attachment referenced as FB-3 which shows the various regulated tariff based and market-based components that the consumer should be able to compare when the customer is deciding whether or not to switch suppliers.

Q. WHAT BILLING FORMAT IS TEP GOING TO USE FOR CHARGING STANDARD OFFER CUSTOMERS AND DIRECT ACCESS CUSTOMERS?

A. TEP does not know what its billing format will be, according to its response to Commonwealth's data request. TEP is apparently resistant to disclosing its unbundled rates, which is not surprising considering the evolutionary process we experienced during the APS proceeding in attempting to find the unbundled billing format. As I mentioned before, the billing format should clearly reflect the line items service and the CTC for both the Standard Offer customer and the direct access customer if electric competition is to become a reality.

The billing format does not have to be unreadable and complex. The utilities try to show numerous and more costly line items for Direct Access service, so that the customer will be so confused that they won't switch to an alternative provider. The Commission should not allow that to happen.

Q. HOW WILL CUSTOMERS BE ABLE TO DECIDE IF THEY WILL SAVE IN BUYING COMPETITIVE SERVICES?

A. Under the Settlement, customers will not be able to make that decision. TEP claims it will assist customers in understanding the process so that the customers can make informed decisions. As a practical matter, TEP's approach creates a barrier to entry. Even though TEP claims it will inform customers with bill stuffers, brochures and a consumer service line, the average customer will not have enough information to make a decision. It is unreasonable to expect customers to prepare calculations, or expect the customer to make phone calls to TEP in order to understand how to make those calculations.

Q. WILL THE USE OF A SAMPLE BILL BE OF ASSISTANCE TO CUSTOMERS?

A. For the most part, a sample bill is not helpful. Commonwealth has requested an illustration and TEP has said that it has not prepared one as of yet. Furthermore, the generation shopping credit and the credit for metering, meter reading and billing and collection services should clearly be stated on the customers individual bill so that they can easily make the choice. Most customers can not make the comparisons to a sample bill. As we have learned in the APS Settlement proceeding, the utility experts cannot come to the same conclusions when they were presented with the same facts. It is unreasonable to expect the busy housewife or business owner to try to make that comparison.

Q. TEP CLAIMS THE RATES WILL BE FROZEN THROUGH THE YEAR 2008 EXCEPT FOR CERTAIN ADJUSTMENTS THAT ARE UNDEFINED IN THE SETTLEMENT. PLEASE EXPLAIN HOW THIS MIGHT AFFECT COMPETITION.

A. The freeze on TEP's rates through the year 2008, except for adjustments to be made by TEP and the other Settling Parties, creates a barrier to entry. If the cost of service declines, TEP will overrecover on its distribution charges. Furthermore, TEP has the flexibility to work with the Settling Parties in raising rates for its distribution services without public input.

VII. TEP SHOULD DIVEST ITS GENERATION AT AUCTION AS INITIALLY PROPOSED

Q. THE SETTLEMENT PROVIDES THAT TEP WILL TRANSFER ITS GENERATION AND OTHER COMPETITIVE ASSETS TO A TEP SUBSIDIARY AT MARKET VALUE. WHAT IS YOUR UNDERSTANDING OF MARKET VALUE?

A. Market value of generation units and other competitive assets should be determined by an open auction process to assure that TEP's subsidiary, if it is the highest bidder, has paid the price as determined by a willing buyer and a willing seller. Other bidders might view the value of these assets more favorably or be able to operate those competitive assets more efficiently. Thus, others might be willing to pay more for those assets than TEP's calculation of "market value."

Q. HOW DOES TEP PROPOSE TO SELL ITS GENERATION AND OTHER COMPETITIVE ASSETS IF IT IS NOT GOING TO USE AN AUCTION?

A. According to the TEP response to the data request, TEP is <u>not actually using market values.</u> TEP proposes to use the generally accepted accounting principles (GAAP) and determine that value using the discounted future cash flows as described in Statement of Financial Accounting Standards No. 121 *Accounting For The Impairment of Long-Lived Assets And For Long-Lived Assets To Be Disposed Of* ("FAS 121"). This is the same method TEP used in figuring its $250 million of above-market generation plant costs. In other words, TEP will estimate the future cash inflows from those competitive assets and deduct the future expected cash outflows to determine what it calls "market value." TEP is merely using the net income stream in deciding what price its affiliate should pay for those competitive assets. TEP's value might be much less than those competitive assets might bring on the open market. As a consequence, it is highly likely that TEP could sell its generation to others at "market" prices and at the same time keep its customers from receiving "market" priced power from competitors. In my view, this asset transfer will continue with TEP's vertical monopoly since it will still be owning and controlling all of its generation and other competitive assets. Only the shareholders will benefit and TEP's customers will be saddled with the same high cost of TEP's generation, plus the additional CTC charges.

Q. DO YOU HAVE OTHER REASONS FOR SUPPORTING THE AUCTION OF TEP'S COMPETITIVE ASSETS?

A. Yes, the use of the auction approach would reduce the CTC of TEP's customers. Revenue received from the auction, which is above the book value of those competitive assets, could be used to pay down TEP's large claim to stranded costs. By reducing the CTC, TEP's customers would experience the benefits of competition sooner. Furthermore, TEP's customers, and not its shareholders, should be entitled to this net revenue between the market value and book value of those assets.

Q. WOULD IT BE PRACTICAL FOR TEP TO AUCTION ITS ASSETS?

A. Yes, I believe it would be practical for TEP to auction its generation and other competitive assets. In fact, TEP filed testimony in the Proposed APS/TEP Settlement last year in which TEP's investment banker expert from New Harbor, Inc. reached the same conclusion. Mr. John G. Paton said in his testimony that New Harbor, Inc. "recommends that TEP proceed with an auction sale because it is more likely to give TEP and the Commission the greatest assurance regarding the consequences of the divestiture, to ensure the best price for the assets, to attract and satisfy the largest number of potential owners, and is the most consistent with the regulatory process." (at page 4, lines 24-28). I believe Mr. Paton's reasons for the auction of TEP's generation assets are valid. Mr. Paton addressed the auction process and he concluded that approximately 15 utilities sold mostly gas-fired generation assets for prices from less than one to over 5 times their book values. He prepared a chart that confirms those sales, and I'm attaching Mr. Paton's Direct Testimony as Attachment FB-4.

Q. HOW WOULD YOU ADDRESS TEP'S CONCERN ABOUT ITS FINANCIAL VIABILITY IN THE FUTURE IF IT CANNOT KEEP THIS EXCESS REVENUE?

A. TEP mistakenly relates the generation and competitive services (metering, meter reading and billing & collection) with its distribution ("wires") business which will continue to be regulated. TEP should remain viable financially so as to operate its distribution business. The Standard Offer and Direct Access rates give TEP its cost of service <u>and</u> an appropriate rate of return on that distribution business. If TEP claims it cannot operate the distribution business with this regulated guaranteed return, it could and perhaps should sell the distribution system to someone who will operate it more efficiently. The Commission should not reward TEP for uneconomic or poor past business decisions by allowing TEP to retain the above market value of competitive assets. TEP's customers should be the beneficiaries of that excess revenue, in the form of reduced CTC payments to the generation owner, particularly since TEP's customers have been paying high rates under the old monopoly system.

VIII. TEP's GENERATION OWNERSHIP CREATES MARKET POWER CONCERNS

Q. DO YOU HAVE CONCERNS ABOUT TEP's CONTINUED OWNERSHIP OF GENERATION AND OTHER COMPETITIVE ASSETS?

A. Yes. If TEP transfers its generation asset to a wholly-owned subsidiary it will be able to set the price of generation in its service area. Existing transmission contracts to deliver its generation power to the TEP service area may give TEP preferential treatment in so far as wholesale access. As a result, TEP could set the price for that power at levels that make it difficult to compete.

XI. TEP'S MUST-RUN UNITS GIVE IT MARKET POWER

Q. TEP CLAIMS IT HAS SEVERAL MUST-RUN GENERATION UNITS, PLEASE DESCRIBE HOW THAT INFLUENCES MARKET POWER.

A. TEP has several must-run units to serve electricity within the load pockets of TEP's service area. The cost of those must-run units is embedded in the Direct Access tariffs. This again limits the ability of competitors to enter the TEP market, particularly because of the way it ties the <u>wholesale</u> generation costs to its MGC.

Q. HOW WILL TEP'S TREATMENT OF MUST-RUN UNITS AFFECT COMPETITION?

A. TEP proposes to bill scheduling coordinators for "variable" must-run generation, under Section 4.2 of the Settlement. This is another barrier to competition. Commonwealth would have to include those costs on top of the inadequate <u>wholesale</u> MGC when a customer is billed. As I discussed before, the MGC and Adder do not provide any margin for <u>retail</u> service costs or potential profit. With this additional must-run cost, TEP will be assured that no competition will occur in its service area.

Q. CAN THIS MUST-RUN ISSUE BE RESOLVED WITH AISA PROTOCOLS?

A. No, I do not believe the must-run issue should be deferred to the Arizona Independent Scheduling Administrator, for several reasons. These must-run units affect whether or not retail competition can occur. The AISA is essentially controlled by the Arizona utilities which own transmission access. Consumers and new entrants have virtually no meaningful voice in the process to assure the public that actual and significant retail electric competition will occur in Arizona. Furthermore, these protocols are not in evidence in this proceeding and the

Commission has no idea as to how or what full cost will be imposed on Standard Offer and Direct Access customers for these must-run units.

X. LOW-INCOME ASSISTANCE PROGRAMS ARE NOT AN ISSUE.

Q. SHOULD LOW-INCOME ASSISTANCE PROGRAMS CONTINUE UNDER ELECTRIC DEREGULATION?

A. Yes, low-income assistance programs have not been an issue, as far as I know in Arizona. The approval or rejection of this Settlement should not affect the Commission's public policy decisions regarding these programs. I would add that any low-income assistance program should be transferrable so that when a competitor provides service to that customer, the appropriate credits from the System Benefit fund of the utility is used for the benefit of that low-income consumer.

XI. AFFILIATE TRANSACTIONS SHOULD BE REGULATED BY RULE NOT BY A CODE OF CONDUCT

Q. TEP HAS PROPOSED ITS OWN CODE OF CONDUCT. WILL IT BE ADEQUATE TO ADDRESS AFFILIATE TRANSACTIONS AND POTENTIAL MARKET ABUSES?

A. Even though TEP has proposed its own Code of Conduct, I believe the Electric Competition Rules should consistently address all utility transactions with its subsidiaries and affiliates. With each utility drafting its own guidelines, consumers, competitors and the Commission will have difficulty understanding the "rules of the road" as it pertains to a particular utility. Because the utility is the drafter, the utility will tell competitors and the Commission what it means. This is like asking the fox to write the rules for protecting the hen house. All parties and the Commission should be involved in developing these affiliate transaction rules, as were previously included in the Electric Competition Rules.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE PROPOSED INTERIM CODE OF CONDUCT PREPARED BY TEP?

A. Yes, in at least two respects. First, the Proposed Interim Code of Conduct does not provide for performance audits, as required in the former Affiliate Transaction Rules of the Commission. These performance audits, of course, should be paid for by TEP's shareholders, and not the customers, because the creation of competitive affiliates is for the benefit of TEP and its parent company and their shareholders. Second, the Proposed Interim Code of Conduct is unclear as to how the Commission may monitor its compliance and as to how customers and competitors may seek relief if there is noncompliance with the Code. If the Affiliate Transaction Rules were adopted, it would be clear as to how the Commission, consumers and competitors could seek relief if there is reason to believe the Rules were not being followed.

XII. CONCLUSION AND SUMMARY

Q. SHOULD THE COMMISSION APPROVE THE SETTLEMENT WITHOUT MODIFICATION?

A. No, I urge the Commission to object the Settlement in its entirety. If not, I would urge that the Settlement be revised to include a market generation credit based upon TEP's embedded costs of generation and the other recommendations I've made.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Before competition will occur in the TEP service area, it is my opinion and recommendation that the Settlement be rejected. I do not believe it is in the public interest because the MGC and limited "wholesale" Adder does not reflect the actual cost of generation being paid by

TEP's Standard Offer customers. Retail marketing costs are not accounted for neither the MGC nor Adder. As a result, I do not believe any ESP will be able to sell competitive generation. I strongly recommend that the Commission require TEP to give customers a "generation shopping credit" equal to the full cost of TEP's generation. TEP should be entitled to a CTC equal to the net amount of stranded costs it has not recovered after the auction sale of its generation units. The CTC should apply equally to those customer who purchase Standard Offer or Direct Access services, and be appropriately reflected on the bill for each. The Direct Access tariffs should include a "shopping credit" for metering, meter reading and billing & collection services that is equal to average full embedded cost for each customer class.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

C:\Commonwealth\Pleadings\TEPSettlement\Testimony.TEP

Attachment FB-1

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
Commissioner – Chairman
RENZ D. JENNINGS
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1602 et seq.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-160 et seq.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-00000C-94-165

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

On the APS and TEP Settlement Agreements

On behalf of the
Residential Utility Consumer Office

November 30, 1998

EXECUTIVE SUMMARY

My initial review of the proposed Settlement Agreements between the ACC Staff, Arizona Public Service Co. (APS) and Tucson Electric Power (TEP) leads me to conclude that both Agreements should be rejected in their current form. The key reasons why the Agreements should be rejected are:

1. The Agreements were negotiated without significant input by most of the parties to this docket and, thus, they do not represent a reasonable balance of stakeholder interests.
2. The Agreements include entirely new policies and proposals that have not received any attention thus far by parties to these dockets, and therefore, have not been adequately analyzed in the context of this docket.
3. The Agreements will not achieve the Commission's goal of establishing a competitive retail market for power in Arizona. Furthermore, the rate decreases promised to standard offer customers from these Agreements are substantially smaller than those rate decreases that have accompanied retail competition in most other states.
4. Both Agreements will likely lead to ratepayers over-paying (paying more than 100 percent) of stranded costs for both Companies, especially for APS.
5. Both Agreements set the generation credit for customers leaving the Standard Offer Service at the cost of <u>wholesale</u> power, and, therefore, no reasonable level of <u>retail</u> competition is likely to ever result.
6. The proposed sale of generating assets to APS from TEP would likely lead to the ability of APS to exercise additional horizontal market power, particularly in light of the load pockets that are likely to exist in Arizona. This would unjustifiably raise the cost of electric generation to ratepayers in Arizona, and, perhaps, in neighboring regions as well.

7. The transfer of generation assets from TEP to APS and the transfer of generation assets from APS to its unregulated marketing affiliate should both occur at a fair market value. None of these assets should be transferred at their net book value.

8. The proposal that TEP become the owner of the high voltage transmission grid within Arizona does not seem workable, and it might increase transmission rates to the Salt River Project, AEPCO, and WAPA ratepayers. In addition, the ACC does not have jurisdiction to implement this proposal, because they do not have jurisdiction over SRP and WAPA.

9. The APS Agreement would likely allow APS to over-earn profits, by keeping the return on equity at inappropriately high levels. APS' and TEP's transmission and distribution rates should be re-set utilizing cost-of-service principles from the ground up, and a new return on equity should be established.

10. Based on a detailed study of potential load pockets in Arizona, the Commission must determine which generating units of APS and TEP are must-run units, and an appropriate market-based price cap mechanism for the units should be proposed to FERC, which has jurisdiction.

11. The Commission must approve the correct procedure for TEP's divestiture of its power plants not being transferred to APS, including how the plants should be grouped or "bundled" for sale to different generation owners. Neither APS nor its subsidiaries should be allowed to bid for TEP's other power plants.

12. The Commission must review the reasonableness of TEP's proposed interim transition charge until its divestiture process has been completed.

13. In case TEP does not decide to divest it's remaining generating units, the Commission must further define the net lost revenues methodology ahead of time that TEP is planning to use to compute stranded costs.

14. The Commission should not grant all of the waivers being requested by TEP and APS.

I. QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Dr. Richard A. Rosen. My business address is Tellus Institute, 11 Arlington Street, Boston, MA 02116-3411.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a B.S. in Physics and Philosophy from MIT, an M.S. in Physics from Columbia University, and a Ph.D. in physics from Columbia University. Currently I am a senior research director at Tellus Institute, as well as executive vice-president of the Institute. I am also the manager of the Institute's Electricity Program.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF TELLUS INSTITUTE.

A. Tellus Institute is a non-profit organization specializing in energy, natural resource, and environmental research. Within Tellus Institute, the Energy Group focuses on energy and utility research areas which include demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, least-cost utility planning and integrated resource planning, avoided cost analysis, financial analysis, cost of service and rate design, non-utility generation issues, bidding systems, incentive regulation, cost-of-capital analysis, and utility industry restructuring.

Q. PLEASE ELABORATE ON TELLUS' EXPERIENCE WITH ELECTRIC UTILITY SYSTEM SUPPLY PLANNING.

A. The Energy Group has had wide experience assessing utility system supply options on both a service area and a regional basis. These assessments have encompassed all types of generation plant, transmission plant, purchases of capacity and energy, fuel purchases and contracting, central station district heating and decentralized cogeneration plants, and alternative sources of energy such as wind, biomass, and solar energy connected to electricity grids. These assessments have dealt with the technical, economic, environmental, regulatory, and financial aspects of supply planning, including the relationships between supply planning, load forecasting, rate design, and revenue requirements. Tellus Institute also has reviewed the prudence of many past supply planning decisions by utilities.

Q. PLEASE REVIEW YOUR EXPERIENCE IN THE AREA OF UTILITY PLANNING.

A. Power supply system modeling, integrated resource planning, and electric industry restructuring has been the major focus of my activities for the past 18 years. My research and testimony in this area began in 1980, and I have testified in numerous cases involving generation planning and the integration of demand and supply technologies on a least-cost basis. For example, I submitted extensive generation planning testimony in the 1980 CAPCO Investigation in Pennsylvania in Case No. I-79070315, and in the 1981 Limerick Investigation as well (Case No. I-80100341). In early 1982, I prepared a major report for the Alabama Attorney General's Office entitled "Long-Range Capacity Expansion Analysis for Alabama Power Company and the Southern Company System," and I filed testimony in Docket No. 18337 before the Alabama Public Service Commission. In addition, I testified on the excess capacity issue regarding Susquehanna unit 1 in the 1983 Pennsylvania Power and Light Co. Rate Case (No. R-822169). In 1987, I testified before the Federal Energy Regulatory Commission on NEPOOL's Performance Incentive Program on behalf of the Maine Public Utilities Commission in Docket No. ER-86-694-001. In 1989, I testified before the Pennsylvania Public Utility Commission on excess capacity and ratemaking treatment regarding Philadelphia Electric Co.'s Limerick 2 nuclear unit. This work was performed on behalf of the Pennsylvania Office of Consumer Advocate in Docket No. R-891364. I also testified in Vermont in Docket No. 5330 on the cost-effectiveness of the proposed purchased power contract between the Vermont utilities and Hydro-Quebec.

Due to my extensive regulatory experience in the public interest, as outlined above, in 1988 I was chosen to serve a 3-year term on the Research Advisory Committee of the National Regulatory Research Institute, an appointment made by the public utility commissioners serving on the NRRI Board of Directors. In addition, within the last 2 years, I have been the project manager on contract research that the Tellus Institute has performed for the U.S. Department of Energy, the U.S. Environmental Protection Agency, the National Association of Regulatory Utility Commissioners (NARUC), the New England Governors' Conference, and the National Council on Competition in the Electric Industry.

In the last 2 years, I have spent most of my time analyzing electric utility restructuring issues.

I testified before the New Hampshire Public Utilities Commission on issues affecting the design of the state's pilot programs (Docket No. 96-150 and market power (Docket No. DE 97-251), and I testified before the New York Public Service Commission on stranded costs, market structures, and other issues related to the ConEd's, NYSEG's, and RG&E's restructuring plans. In early 1998, I testified on the full range of policy issues connected with the establishment of stranded cost policies by a state PUC in Arizona Docket No. U-000-94-165. I also have worked or testified on other restructuring issues such as unbundling, stranded costs, retail margins, Standard Offer service, market power, and wholesale market prices in Nevada, New Jersey, Illinois, Texas, Missouri, Delaware, Pennsylvania, and Michigan. The remainder of my experience is summarized in my resume, which is attached as Exhibit___(RAR-1).

II. BACKGROUND

Q. HAVE YOU TESTIFIED IN ANY OF THESE DOCKETS BEFORE?

A. Yes, I have testified in the stranded cost dockets previously.

Q. WOULD YOU PLEASE OUTLINE SOME OF THE KEY PROCEDURAL ASPECTS OF YOUR INVOLVEMENTS IN THESE DOCKETS IN ADDITION TO THE FILING OF YOUR STRANDED COST POLICY TESTIMONY IN JANUARY OF 1998?

A. Yes. TEP and APS filed proposed unbundled tariffs on December 30, 1997 and February 13, 1998 respectively. In response to these filings, RUCO issued data requests to both TEP and APS on July 24, 1998, as well as a follow-up request on September 30, 1998. TEP and APS then filed their separate stranded cost plans on August 21, 1998. RUCO issued data requests about these plans to TEP on August 31, September 1, and September 4, and to APS on August 31, 1998. RUCO then filed comments on both stranded cost plans with the Commission on September 21, 1998.

The two new proposed Settlement Agreements were filed at the Commission on November 5, 1998. RUCO followed up these filings by issuing data requests for APS on November 10, 11, 18, and 25 and to TEP on November 6, 12, and 13, 1998.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Tellus Institute was retained by the Residential Utility Consumer Office to analyze the various filings related to the unbundled service tariffs, stranded cost recovery proposals for APS and TEP, and various other aspects of their restructuring proposals. One purpose of my testimony is to suggest ways in which the proposed plans could be modified to more closely adhere to the various rules and policies the ACC adopted in the various restructuring dockets, and to principles of fairness. Another purpose of my testimony is to suggest ways in which Arizona's transition to competition in the supply of electricity-related services could be made more successful than the proposed settlement is likely to be. Finally, my testimony will indicate why more time is needed for the parties to analyze the details of the proposed Agreements. One reason why more time is needed is that this Agreement was still incomplete, at least up until November 24, 1998, when I received a copy of Mr. Davis' testimony.

Q. SHOULD THE COMMISSION APPROVE THE TWO PROPOSED SETTLEMENT AGREEMENTS IN THEIR CURRENT FORM?

A. No, the Arizona Corporation Commission should not approve the two proposed Settlement Agreements in their current form. The Agreements should be rejected.

Q. WHY SHOULD THE COMMISSION CONSIDER REJECTING OR AT A MINIMUM CHANGING THESE TWO SETTLEMENT AGREEMENTS WHICH THE COMMISSION STAFF, TEP, AND APS FOUND ACCEPTABLE?

A. These two Settlement Agreements were developed quickly, with very limited input from parties other than TEP, APS and the ACC staff. In light of this, it is not surprising that other parties might be able to offer critical beneficial suggestions for improvement of the important issues dealt with in these Agreements. Furthermore, even a quick review of these Settlement Agreements has uncovered many serious problems with them. The key problem is that the Agreements will not achieve the Commission's restructuring goals. In particular, as with restructuring agreements reached in California, Massachusetts, Rhode Island, and New Hampshire, little or no retail competition will result from these Agreements. There are many issues that need considerable more analysis before the Commission will have sufficient information on which to make a decision.

Q. IS THE PROCEDURAL SCHEDULE ISSUED BY THE ACC ON NOVEMBER 25, 1998 REASONABLE IN LIGHT OF THE IMPORTANT ISSUES RAISED IN THE PROPOSED SETTLEMENT AGREEMENTS?

A. No. The case schedule for these docket numbers as ordered by the ACC on November 25, 1998 is unreasonable. The compressed case schedules ordered by the ACC on November 25, 1998 should be replaced with case schedules which are greatly extended by several months.

The current schedule does not allow for adequate discovery and analysis of the proposed Settlement Agreements prior to the filing of testimony. Due to the inability of the Residential Utility Consumer Office to adequately address the issues raised by these filings, and the inability of other stakeholders to participate meaningfully in this proceeding, the public interest will not be well served by an Order issued based upon this inadequate record.

Q. GIVEN THE VERY BRIEF PERIOD OF TIME (ABOUT THREE WEEKS) THAT YOU HAVE BEEN ABLE TO REVIEW THE TWO PROPOSED SETTLEMENT AGREEMENTS, WHAT NEW PROPOSALS HAVE BEEN MADE IN THOSE AGREEMENTS FOR THE FIRST TIME THAT, THEREFORE, REQUIRE CONSIDERABLE FURTHER ANALYSIS?

A. Given that I have only been able to review these two proposed Settlement Agreements for about three weeks, and given that they contain many new proposals that have not previously been discussed among all the parties to these cases, I find that substantially more analysis is required of, at least, the following <u>new</u> proposals:

1. The proposal that TEP transfer certain generation assets directly to APS in return for certain APS transmission system assets.
2. The proposal that TEP's generating assets transferred to APS should be valued at $165 million.
3. The proposal that APS' current generating assets should be transferred at net book value to an unregulated APS marketing subsidiary.
4. The proposal that TEP should become the owner of all transmission system assets within Arizona.
5. The proposal that APS should freeze its rate of return on equity at its current level.

6. The proposal that TEP should have primary control over the divestiture process for its remaining generating units and that these units could be sold as a single bundle.
7. The proposal that the market generation credits for Standard Offer Service customers for both APS and TEP be set on the basis of wholesale market prices and not retail market prices in order to achieve retail competition.
8. The proposal that price caps for APS' must-run generating units be set based on current cost-of-service levels, and not market-based wholesale prices.

III. THE TWO SETTLEMENT AGREEMENTS

APS

Q. PLEASE SUMMARIZE THE SETTLEMENT AGREEMENT BETWEEN APS AND ACC STAFF.

A. *Market generation credits.* Under the Settlement Agreement, APS customers who choose to receive generation service from a non-APS Energy Service Provider ("direct access customers") would receive a market generation credit (MGC) in lieu of APS generation service. The credit would be based on the NYMEX prices for electricity futures at the Palo Verde Exchange in southern California and the California Power Exchange prices, plus a line loss adjustment and an adder. It would be calculated for each month of a given calendar year during November of the preceding year.

"True-Up" of CTC. The NYMEX Palo Verde electricity futures prices used to set the CTC for each month, which would be from November of the preceding year, would be compared with the NYMEX futures prices during the last three days before the month in question. Differences, positive or negative, would be considered over- or under-recovery of monthly

stranded costs, and would be accumulated. The accumulated amount would be spread over the direct access sales of the following year (pp. 2-3, Exhibit A).

Adjustment for line loss. The projected market price of power, based on the NYMEX futures price, would be multiplied by 1 plus a line loss factor to account for losses during transmission and distribution.

Adder. To calculate the market generation credit, APS would apply an adder of approximately 3 mills (thousandths of a dollar) per kWh to the projected wholesale generation price based on the NYMEX Palo Verde futures price. The adder reflects additional components of the wholesale price of power. The adder would be adjusted for each rate class according to the differences between the class load factor and the system average load factor.

Redesigned rates effective January 1, 2001. The Settlement Agreement would allow APS to file a new rate case by September 1, 1999 and would require the ACC to rule that new APS rates be effective January 1, 2001. These rates would be "revenue neutral" and would not change APS' currently authorized cost of capital. However, APS' rate case filing would propose to "realign Standard Offer and unbundled rates in accordance with appropriate cost allocation and rate design principles."

Regulatory asset recovery. APS would be allowed to recover 100 percent of regulatory assets.

Exchange of assets with TEP. The Settlement Agreement would give APS and TEP "all requisite approvals necessary" for a transaction in which APS would sell its 345 kV and 500 kV transmission assets to TEP and buy TEP's 279 MW of ownership interests in the Four Corners Generating Plant and Navajo Generating Plant.

Transfer of generation assets to APS' unregulated affiliate. APS is proposing to transfer its generating plant assets to its unregulated marketing affiliate at net book value.

Standard Offer rates. In Arizona, "Standard Offer...means Bundled Service offered...to all consumers...at regulated rates" (A.A.C. R14-2-1601(38)). Presumably, under the Settlement Agreement, APS' current rates would become its rates for Standard Offer service. The rates for Standard Offer service would then decline by 1 percent in 1999 and again by 1 percent in 2000. Standard Offer rates for residential customers only would decline by a further 1 percent in 2001 and again in 2002. The annual reductions would be larger than 1 percent if the cost savings incentive formula in ACC Decision 59601 yielded a reduction of greater than 1 percent. Also, APS is proposing to cap the rates of its must-run generating units on a cost-of-service basis.

Unbundled rates. It is not entirely clear whether unbundled rates (with the MGC in place of generation) would match Standard Offer rates. The Settlement Agreement merely states that "the Company's unbundled rates will reflect the embedded cost of service for all functions as approved by the Commission" (p. 2). The unbundled rates would decline in 1999 and 2000 to the same degree that the Standard Offer rates would decline, but would not decline in 2001 and 2002, as Standard Offer residential rates would.

Customer transition charge (CTC). The customer transition charge, described primarily in Exhibit A, would apply to direct access customers, that is, to customers paying unbundled rates. Through the end of the year 2004, it would recover the difference between the Standard Offer generation rate (implicit in the Standard Offer tariffs) and the market generation credit. However, it is not clear whether it would be calculated for all customers in one aggregated group or separately for the customers on each tariff. The CTC would not be allowed to drop below zero.

Conditions for collection of CTC. The CTC would be contingent on APS divesting its transmission assets but not contingent on APS divesting its generation assets. In addition, if the ACC concluded that APS had significant market power and had manipulated the market price for power in the region, it could terminate the CTC.

Resolution of litigation. The Settlement Agreement would require APS to withdraw all litigation against the ACC, and would, instead, direct APS to help the ACC overcome any litigation by other parties in opposition to the ACC's Electric Competition Rules.

<u>TEP</u>

Q. PLEASE SUMMARIZE THE PROPOSED SETTLEMENT AGREEMENT WITH TEP.

A. *Unbundled service rates.* The Settlement Agreement describes changes to the unbundled service rates TEP filed in its December 31, 1997 filing in ACC Docket No. E-01933A-97-0772. The new unbundled service rates were to be submitted to the ACC by November 15, 1998. According to the Settlement Agreement, they were to reflect a new TEP cost of service study already approved by the ACC and a rate reduction of 1.1%. Since stranded costs cannot be accurately calculated until a final result of unbundling the generation component of current rates is known, more time will be required to analyze this new filing.

Recovery of positive stranded costs. TEP's stranded costs, both its regulatory assets and its other positive stranded costs, are to be completely recovered from ratepayers over a period of 6-8 years from the date that the final stranded cost amount is calculated. In fact, Exhibit C to the filing, which was delayed until November 10, 1998, provides a precise estimate for the final stranded costs of $821 million net present value (NPV), but the year in which the present value (PV) dollars is expressed is not clear. This exhibit also computes a CTC of 1.82 cents per kWh for 8 years beginning in 2001. The basis for these results needs to be reviewed.

Market generation credit. In lieu of generation service, direct access customers will receive a "market generation credit" for each kilowatt-hour they use. This credit will be revised each quarter based on the prices of wholesale electricity futures, which will be adjusted upward by a credit of 2.6-4 mills (thousandths of a dollar) per kilowatt-hour, depending on the customer class involved. These additional costs are intended to reflect ancillary services, capacity reserves, and other generation costs at the wholesale level.

Interim stranded cost recovery. Until the divestiture of all generation assets has either succeeded or failed, and the stranded cost of each is known, TEP will continue to collect its annual strandable costs from both Standard Offer and direct access customers. This will most likely be from 1999-2000. Standard Offer customers will pay those stranded costs through their Bundled Service rates, while direct access customers will pay them through an interim transition charge intended to equal the difference between the Standard Offer generation rate and the market price of generation. These stranded costs paid during 1999 and 2000 will add to the $821 million estimate of stranded costs to be paid from 2001-2008, making a total stranded cost recovery that will probably exceed $1.0 billion (NPV) as estimated under this agreement.

Recovery of negative stranded costs For those assets with negative stranded costs, TEP would be entitled to "borrow" the negative stranded cost amounts for the purpose of purchasing transmission assets in Arizona. In the meantime, TEP would pay its customers the equivalent of interest on the "loan" from ratepayers by reducing jurisdictional rates by an amount equal to the return on the negative stranded cost amount multiplied by TEP's cost of capital. At some unspecified future time, TEP would begin to repay the "principal" over a period of ten years. This appears to be an internal financing mechanism for new transmission investments. It is not clear why TEP is mixing up financing issues for transmission and stranded cost recovery issues in this way. This issue needs considerable further analysis.

Transco monopoly on transmission in Arizona. The Agreement calls for TEP's transmission affiliate, Transco, to become the only builder and owner of transmission facilities in the state of Arizona. The potential impact of this proposal on the transmission rates of other utilities and coops in Arizona also requires further analysis.

Asset swap with APS. TEP would sell its interest in the Navajo and Four Corners generation facilities to APS for $165 million, and would buy all of APS' transmission assets with voltages of 345 kV and above for $168 million. The potential impact of this sale of generation plant to APS on horizontal market power in the region requires substantial analysis before it is approved. In addition, a process needs to be established for Commission review of the reasonableness of the $165 million price for those generation assets of TEP. The transfer price must reflect a reasonable market price in order that TEP ratepayers do not subsidize APS ratepayers, or vice versa.

Auction. TEP would auction those generation assets that it would not sell to APS. The degree of control that TEP should be allowed to have over the auction process needs significant review.

Failed auction. If the ACC did not find any of the bids acceptable for any of these other generating units, it could declare a failed auction and allow TEP to keep the generating asset. In that case, the stranded cost of the generating asset would be determined through a "net lost revenues" method. The Agreement provides few details of the precise "net lost revenues" method to be employed. These details must be specified as part of any reasonable settlement, e.g., the time period over which stranded costs would be calculated.

Failure to divest. If TEP chose not to divest for some reason other than a failed auction, it would be allowed stranded cost recovery sufficient to maintain financial viability, but would not be guaranteed 100% recovery of positive stranded costs. However, the Agreement contains no clear criteria for what constitutes "financial viability." These criteria must be clearly stated.

Waivers. The Settlement Agreement would codify waivers of various ACC regulations. Many of these waivers would obviate the requirement that TEP or its affiliates reveal to the ACC certain information about those affiliates. Whether this proposal is reasonable or not requires detailed analysis. However, on their face, some of the waivers do not appear to be justified.

Resolution of litigation. The Settlement Agreement would require TEP to withdraw all litigation against the ACC, and would, instead, direct TEP to help the ACC overcome any litigation by other parties in opposition to the ACC's Electric Competition Rules.

IV. CONCLUSIONS AND RECOMMENDATIONS

APS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE PROPOSED APS SETTLEMENT AGREEMENT.

A. 1. Based on my previous testimony in this docket, APS has a negative strandable cost amount. Therefore, it is not appropriate for APS to collect only additional positive amounts of stranded costs from customers, as APS would under the Settlement Agreement. Rather, the Commission should determine to what extent APS may have negative stranded costs, and APS should then fully return its negative stranded costs to customers through a wires credit. Anything short of this would constitute excess retention by APS of ratepayers' money, and would be completely inequitable. The Commission needs to review APS' claim that its stranded costs are positive in a properly adjudicated hearing.

2. Little or no competition would occur in APS' service territory as long as the terms of the Settlement Agreement remained in effect. This is because the Settlement Agreement calls for a market generation credit that approximates the *wholesale* price of generation. Retail competitors would not be able to match this *wholesale* price. Experience to date in Massachusetts, New Hampshire, Rhode Island, and California has amply demonstrated that if the market generation credit approximates the wholesale price, little or no competition

results. In addition to the modest *wholesale* adder of approximately 3 mills proposed in the Settlement Agreement, the market generation credits should incorporate a *retail* adder for each customer class, which accounts for the additional costs of providing *retail* generation service. In my January 1998 testimony in ACC Docket No. RE-00000C-94-0165, I estimated that the retail adders in Arizona should be 0.82-1.18 cents per kWh for small customers such as residential customers and 0.64-0.85 for large customers such as industrial customers. I suggest starting with the upper ends of these ranges because they were conservatively estimated, and because utilizing the upper end of the range would facilitate the onset of retail competition. The size of the retail adder could be reduced in the future if retail competition proves to be successful.

3. Ratepayers must be assured that transferring certain of TEP's generating units to APS will not increase APS' ability to exercise horizontal market power. Such assurance is not likely to be possible, but certainly cannot be made until a detailed study of horizontal market power within Arizona can be completed. Such a study would probably take at least a few months before this aspect of the proposed settlement could even be intelligently discussed and considered by the Commission. This study must also include an analysis of the extent to which Phoenix and Tucson are load pockets, and therefore the hours in which any generation unit owned by APS would be a must-run unit. If it becomes apparent from such a study that horizontal market power could be exercised by APS, then appropriate mitigation measures must be put into place.

4. Allowing APS to retain its currently authorized cost of capital in the rate case filing of September 1, 1999 would likely be highly inequitable, given that interest rates have fallen significantly in recent years. A new, appropriate cost of capital must be established in APS' next rate case that should be used to re-set APS' transmission and distribution rates on a traditional cost-of-service basis from the "ground up."

5. The unbundling process should result in rates for distribution, transmission, and customer service charges that are the same for all Standard Offer and unbundled customers within the same customer class. Therefore, all rate reductions for 2001 and 2002 should apply equally to Standard Offer and unbundled rates. In addition, the 2-4 percent rate decreases scheduled for the Standard Offer rates are far too small to be a reasonable outcome of this Settlement process. This is especially true since the Settlement locks the ratepayers into paying a cost of capital in the next rate case that is too high. Just reducing the current return on equity to a more up-to-date and reasonable level might cause Standard Offer rates to drop by more than 4 percent. In addition, the restructuring process should yield rate decreases of a minimum of 10 percent beyond the level of just and reasonable rates under traditional cost-of-service regulation.

6. APS should not be allowed to transfer its generating assets to an unregulated subsidiary at their net book value. To the extent that these assets have negative stranded costs, this would allow this subsidiary to profit at ratepayer expense. Thus, not only is the proposed Settlement asking ratepayers to pay positive stranded costs through the CTC for 2000-2004, but the Agreement does not credit ratepayers with these over-payments of stranded costs by requiring the unregulated APS marketing affiliate to reimburse these stranded costs, since overall stranded costs are negative. Whether stranded costs are negative or positive generating assets should only be spun-off to an unregulated affiliate at fair market value, not at net book value.

7. The Commission must determine which APS generating units are must-run units based on a detailed analysis of APS' load pockets. These units should have the wholesale price of power sold capped not at cost-of-service as provided for in the proposed Settlement Agreement, but at a long-term levelized market price for wholesale power. If this is not done, the "price signals" seen by customers of these units will be distorted, and some customers could end up with subsidized rates. This is a situation that restructuring was designed to avoid, not perpetuate.

Stranded Cost Recovery

Q. WHAT WILL LIKELY BE THE VALUE OF APS' TOTAL STRANDED COSTS?

A. RUCO's Comments on APS' stranded cost filing (submitted September 21, 1998 in ACC Docket No. E-01345A-98-0473) present an estimate of APS' strandable costs at the beginning of 1999. The estimate is *negative* \$1.1 billion as revised to cover the period 1999-2020. With the phasing in of competition, these potential benefits of APS continuing to use its generating resources to serve its customers on a cost-of-service basis could become stranded, and APS' ratepayers may not benefit from future use of APS' generating assets unless the Commission takes appropriate action to protect them. Ratepayers would lose these benefits if APS' generating assets are transferred to an unregulated affiliate at net book value instead of at a fair market value. My estimate above for APS' total stranded costs uses exactly the same model and data I relied upon in my January testimony in ACC's competition Docket, No. RE-00000C-94-0165. The only difference is that my earlier estimate, negative \$838 million, had been computed beginning in 1998, and the revised figure is for a period beginning 1 year later. Any stranded cost recovery should be based on up-to-date estimates of stranded costs carefully examined in a litigated proceeding, or based on the actual sale prices of APS generation assets, or on a combination of both.

Q. HOW CAN APS' POTENTIALLY STRANDED BENEFITS/COSTS BE PROPERLY RECOVERED?

A. In the case of APS, it is the *customers*, rather than the Company, that need to recover potentially stranded benefits. The Settlement Agreement can be adapted to accomplish these important ends. APS would simply award all customers a per-kWh stranded cost recovery credit, sufficient to return the total stranded cost amount in present value over some period of time to be determined by the ACC. This credit should be trued up periodically as either actual market prices become known, or generating plants are divested and their sales prices become known. This could include use of the fair market value that the ACC should set for the plant assets being transferred to APS' unregulated marketing subsidiary.

Q. WOULD THIS BE FAIR TO APS?

A. Yes. It would be entirely fair to APS. The Company would enter the competitive wholesale marketplace through its unregulated subsidiary with no Stranded Costs, which by definition would set it on a path to continued normal rates of return over the long run. In addition, APS would still have tremendous advantages such as an initial 100 percent share of the retail market, economies of scale, and proximity to its customers.

Q. WHAT IS THE BASIS FOR THE INAPPROPRIATE STRANDED COST RECOVERY PROPOSAL IN THE SETTLEMENT AGREEMENT?

A. The stranded cost recovery proposal in the Settlement Agreement would collect overestimates of APS' *annual* stranded cost amounts during the next six years when they are positive. In contrast, a proper stranded cost recovery would instead collect the amount of the Company's *total* stranded cost, which is the net present value of the stream of annual stranded cost amounts over the remaining life of APS' generating assets.

The overestimated annual stranded cost amounts to be collected under the Settlement Agreement would very likely remain positive through the year 2004, which is when APS would stop collecting them. These positive amounts contrast sharply with my estimate for total stranded costs, because under the proposal ratepayers would never get to be credited with the negative annual stranded costs that will likely occur after 2004. This is true even if the total stranded costs for APS are much less negative (closer to zero) then I believe they are. If APS has made any recent computation of its stranded costs, I have not yet had the opportunity to review it. Setting the proper level of stranded costs in these dockets is equivalent to setting the overall rate of return on equity in a full rate case. It must be done with equal care and caution, as very large amounts of money are at stake each year in the future.

Market Generation Credit (MGC)

Q. WHAT SHOULD THE MAGNITUDE OF THE MARKET GENERATION CREDIT BE?

A. The market generation credit should be at least as high as the retail market price of generation service. It should be set at the high end of a reasonable range of retail market prices. Otherwise, alternative generation suppliers will not be able to match or beat the price of APS generation service. If the MGC is not somewhat higher than the retail market price, little or no competition will result, just as we have seen this year in California, Massachusetts, New Hampshire, and Rhode Island. Most ratepayers probably need to receive <u>at least</u> 5 percent overall savings on their electric bills before they would be induced to switch suppliers.

Q. IS THE MGC PROPOSED IN THE SETTLEMENT AGREEMENT AT LEAST AS HIGH AS A REASONABLE ESTIMATE OF THE RETAIL MARKET PRICE OF GENERATION?

A. No. The market generation credit proposed in the Settlement Agreement is significantly lower than a reasonable estimate of the retail price of generation service, for two reasons.

First, it is a wholesale, rather than a retail, price. The adder of roughly 3 mills per kWh to be included in the MGC is only enough to cover some additional wholesale generation-related costs, if that. No retailing costs have been included, not even the retailing costs (generation-related A&G) that are currently included in APS' retail rates. Yet, alternative suppliers will necessarily have even higher retailing costs than APS has had under monopoly conditions.

Second, the market generation credit proposed in the Settlement Agreement is based on the NYMEX futures price, which equally weights the prices of electricity between 6 a.m. and 10 p.m, Monday through Friday. The hours not thus included are represented by the NYMEX multiplied by a "light load ratio" which is less than one. (See Exhibit A to the Settlement Agreement for more detail.) In reality, the average wholesale price of a kilowatt-hour is higher than the NYMEX indicates because prices are highest at the times when the most kilowatt-hours are sold. The MGC must be adjusted for APS' load shape, separately, for each customer class.

Q. WHAT DO YOU RECOMMEND TO CORRECT APS' PROPOSED MARKET GENERATION CREDIT?

A. I recommend two simple modifications of the Settlement Agreement to correct APS' market generation credit. The first is the application of a customer class-specific retail adder on top of the wholesale market generation credit which APS proposes. As a first approximation of the appropriate retail adder, I suggest the use of the adders I presented in pages 28-39 of my January, 1998 testimony in ACC Docket No. RE-00000C-94-0165. Since these were conservatively estimated, I believe it would be best to begin with the high ends of the ranges I derived. These are 1.18 cents per kWh for small customers and 0.85 cents per kWh for medium-large customers.

My second recommendation is to start with a more realistic wholesale price. The wholesale market price of generation used in the calculation of the MGC for each customer class should reflect the load curve of that class, rather than a flattened load curve such as that implicit in the formula proposed in the Settlement Agreement's Exhibit A.

Transfer of Generation Assets

Q. IS THERE A PROBLEM WITH LEAVING GENERATING UNITS UNDER THE CONTROL OF APS, EVEN IF THEY ARE FORMALLY OWNED BY AN UNREGULATED AFFILIATE?

A. Yes. The more generation capacity APS owns, the more able it is to raise electricity prices in Arizona through the exercise of market power. The Company already owns a large portion of the generating capacity in Arizona. Under the terms of the proposed APS and TEP Settlement Agreements, APS would be authorized not only to keep the generating assets it currently owns but also to obtain even more from TEP. In addition, many of its generating units may prove to be must-run units in order to preserve system reliability once an analysis of potential load pockets is done within APS' service territory.

Q. WHAT ACTION DO YOU RECOMMEND TO ADDRESS THE ISSUE OF POTENTIAL APS HORIZONTAL MARKET POWER?

A. The amount of generation plan that APS could safely own without being able to exercise horizontal market power must be reviewed so that ratepayers can be assured that transferring additional amounts of generation to APS will not inappropriately increase APS' ability to exercise horizontal market power. Such assurance can not be made until a detailed study of potential horizontal market power within Arizona and neighboring regions can be completed. Such a study would probably take at least a few months before this aspect of the proposed settlement could be intelligently discussed and considered by the Commission. In the alternative, strict price controls for all of APS' generation would have to be kept in place indefinitely, but this would hamper the development of a competitive wholesale market.

Therefore, I recommend that the ACC leave sufficient time for a study of the impact on electricity prices in Arizona of allowing APS to retain its generating assets, and of allowing it to acquire additional generating assets from TEP *prior* to deciding these cases. As noted, this study would require several months, at least, to be performed adequately. This study should be coupled to a thorough study of APS' potential load pockets. This is because the existence of load pockets can substantially accentuate problems with horizontal market power. Finally, the must-run generating units will require price caps for the indefinite future as APS has proposed, and as FERC has approved for must-run units in California. However, the price caps should be at a market-based level of prices assuming that all generation is transferred to APS' unregulated subsidiary at a fair market value. This is so that the price caps reflect the same underlying basis of value assigned to these generating units for transfer purposes, and for the purpose of setting stranded costs.

TEP

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE PROPOSED TEP SETTLEMENT AGREEMENT.

A. The summary of my conclusions and recommendations regarding the proposed TEP Settlement Agreement is as follows:

1. Since new unbundled rates were to be presented to the Commission on or about November 15, 1998, no final determination can be made of either the appropriate interim transition charge for 1999-2000, or the final transition charge for the period 2001-2008, until the parties to the docket have an opportunity to review that new filing, particularly the new proposed generation component of rates, and the new estimate for generation-related administrative and general costs. Resolving the proper values for these two components of rates is critical for computing the two stranded cost recovery charges.

2. The new, late filed Exhibit C contains an estimate of $821 million (NPV) in stranded costs for the period 2001-2008 that is completely undocumented.

The parties need an opportunity to review the basis for this estimate, and to review the reasonableness of the proposed translation of that estimate into the proposed 1.82 cents per kWh CTC for the period 2001-2008. Even more importantly, no calculation has been made of the proposed ITC for the period 1999-2000, and no Settlement Agreement should be approved by the Commission until such a figure is proposed and reviewed by the parties.

3. The proposed market generation credit is simply based on a <u>wholesale</u> price of power not a <u>retail</u> price for power. The wholesale price is much too low to allow for retail competition, and, thus, is anti-competitive. As I testified to in my stranded cost testimony in January 1998, a much higher retail price for power must be used for pricing standard offer generation service. By pricing the generation credit at a wholesale price, no alternative provider can price their power lower, by definition, and, therefore, no competition will result. This is what has already happened in California, Massachusetts, Rhode Island, and New Hampshire. This error must be rectified.

4. TEP should keep its mechanism for collecting stranded costs from ratepayers completely separate from any process that it proposes for financing new transmission investments. Thus, any net income from generation asset sales should not directly be used to fund new transmission investments. In addition, any new transmission investments should pass traditional least cost planning criteria before the Commission should allow such investments to be made. The Commission needs to make sure that TEP will not create new uneconomic investments in transmission, which would be like stranded generation costs.

5. TEP should not be allowed to become the sole or primary owner of all transmission in Arizona until the details of the state or regional ISO are worked out so that ratepayers can be assured that this proposal will not allow TEP to exercise

vertical market power. In addition, TEP's proposal must be studied as to the likely rate impact that it might have for non-investor owned utilities within Arizona, especially for coops and the Salt River Project. Since TEP's cost of capital is higher than their cost of capital, selling their transmission assets to TEP could increase the cost of transmission to the coops and to Salt River.

6. TEP should not be allowed to sell any of its generating assets to APS unless ratepayers can be assured that doing so will not increase APS' ability to exercise horizontal market power. Such assurance can not be made until a detailed study of horizontal market power within Arizona can be completed. Such a study would probably take at least a few months before this aspect of the proposed settlement could be intelligently discussed and considered by the Commission. One aspect of such a study necessarily involves a transmission system analysis to determine to what extent Phoenix and Tucson are load pockets. This will also bear on a determination of which generation units are must-run units.

7. Prior to TEP's divestiture of its generating units, the Commission must determine both which is the best way to group or "bundle" the plants for sale to best mitigate potential market power problems, and what type of price cap will be placed on the must-run generating units. (Note that this price cap must ultimately be FERC approved.) Since both of these determinations will likely offset the sale price of the generating units, they clearly must be made prior to the solicitation of bids.

8. If TEP fails to divest some of its generating units for any reason, the "net lost revenues" methodology that it claims will be used to compute stranded cost administratively must be specified in detail before the proposed Settlement should be approved.

9. The Commission should not grant all of the waivers requested by TEP from the Commission's rules.

Market Generation Credit (MGC) and Interim Transition Charge (ITC)

Q. WHAT MARKET PRICE OF GENERATION SHOULD BE USED IN CALCULATING THE MARKET GENERATION CREDIT AND INTERIM TRANSITION CHARGE FOR TEP CUSTOMERS?

A. The market generation credit for each customer class should be at least as high as the full retail market price of generation service for each class. Otherwise, alternative generation suppliers will not be able to match or beat the price of TEP generation service provided under the Standard Offer. If this is not done, very little competition will result, just as has occurred in California, Massachusetts, New Hampshire, and Rhode Island.

The interim transition charge is simply the difference between TEP's Standard Offer generation rate and the market generation credit, as indicated on page 3 of the Agreement. If the market generation credit is too small, then the interim transition credit will also be too large—it will collect more than TEP's annual stranded costs correctly calculated.

For confirmation of this last point, consider the concept of stranded cost. It is, of course, based on the difference between the utility's cost of generation service and the price the utility can garner in the competitive retail market for its generation. That competitive market price is the *retail* market price, because the competition that TEP will face is for retail generation sales within its own service area. TEP has a tremendous competitive advantage because it is the known provider and customers have to do some work to switch to any other provider. Therefore, if TEP just matched the retail market price, it would hold onto most, if not all, of its generation customers. Thus, the generation credit should be somewhat higher than the expected retail market price if the Commission wants competition to actually begin. (It should be at the high end of a reasonable range, keeping in mind, though, that most customers will not switch without at least being guaranteed a 5 percent saving on their total rate.)

Q. IS TEP'S PROPOSED MARKET PRICE OF GENERATION A RETAIL MARKET PRICE?

A. No. TEP's market price of generation is far lower than the retail price of generation service, for two reasons.

First, it is a wholesale, rather than a retail, market price. The adder of 2.6-4 mills per kWh which TEP proposes to add to the wholesale market price is only enough to cover some additional wholesale generation-related costs, if that. No retailing costs have been included at all; not even the level of costs embedded in TEP's current level of generation-related A&G.

Second, TEP's proposed market price of generation, which is ultimately based on the palo Verde Index, may reflect a flatter, less expensive load curve than that of some or all Arizona customer classes.

Q. WHAT DO YOU RECOMMEND TO CORRECT THE MARKET PRICE OF GENERATION USED IN SETTING TEP'S MARKET GENERATION CREDIT AND INTERIM TRANSITION CHARGE?

A. To correct this serious problem, I recommend at least two simple modifications of the Settlement Agreement. The first is the application of a retail adder on top of the wholesale market price of generation and the wholesale adder which TEP proposes. As a first approximation of the appropriate retail adder, I suggest the use of the adders I presented in pages 28-39 of my January, 1998 testimony in ACC Docket No. U-0000-94-165. Since these were conservatively estimated, I believe it would be best to begin with the high ends of the ranges I derived. These are 1.18 cents per kWh for small customers and 0.85 cents per kWh for medium-large customers.

The second modification I recommend is that the wholesale market price of generation used in the calculation of the MGC and ITC for each rate schedule be a weighted average of the spot market prices and ancillary services, with the price for each hour weighted in proportion to the load curve of the corresponding group of customers.

"Net Lost Revenues" Method of Estimating Stranded Costs

Q. UNDER THE PROPOSED TEP SETTLEMENT AGREEMENT, WHEN WOULD THE "NET LOST REVENUES" METHOD BE EMPLOYED?

A. The TEP Settlement Agreement proposes on pages 3 and 5 that the "net lost revenue" method of estimating stranded costs be used to calculate the stranded costs of those generation assets for which a failed auction is declared.

Q. IS THE "NET LOST REVENUES" METHOD APPROPRIATE FOR THIS PURPOSE?

A. Yes. The net lost revenues method is a valid framework for administratively calculating stranded costs. However, the details of its implementation have a considerable impact on the results.

Q. WHAT ACTION DO YOU RECOMMEND TO FACILITATE A REASONABLE ESTIMATION OF STRANDED COSTS BY MEANS OF THE "NET LOST REVENUES" METHOD?

A. I recommend that the stranded cost estimates be examined in a fully litigated proceeding for TEP, and rejected or revised if necessary, before being approved.

I also recommend that the ACC and its staff be careful not to pre-approve any parameters of the specific net lost revenues estimation methodology if those parameters would tend to lead to an overestimation of stranded costs. For example, a proper final estimation of stranded costs generally requires the use of a retail market price of generation rather than a wholesale market price of generation, just as a proper calculation of the interim transition charge requires the use of a retail market price, as discussed above in the section about the MGC and the ITC. In addition, stranded costs must be calculated over a sufficiently long period of time. If the ACC were to approve the provision (on page 2 of the Settlement Agreement and on sheets 1 and 4 of Exhibit B) calling for the use of a wholesale market price in setting the ITC now, this precedent might be difficult to overcome when the time arrived to estimate the final stranded costs of TEP assets.

Asset Swap with APS

Q. WHAT IS YOUR OPINION OF THE PROPOSED ASSET SWAP BETWEEN APS AND TEP?

A. I am aware of two major problems with the swap, from the perspective of TEP ratepayers. First, it may undervalue TEP's generating assets. If APS is willing to pay $165 million in a swap, then it is probably willing to pay at least as much in an auction for those assets—and some other party might be willing to pay more. The Commission will have to make an administrative determination of whether or not $165 million is a fair market price for those assets. A hearing process must be included in the proposed Agreement to accomplish this.

Second, the further accumulation of generation assets by APS increases the potential for APS to raise generation prices through the exercise of horizontal market power. This is already a serious risk of a competitive wholesale market in Arizona, even without APS acquiring additional generation assets. This is because Phoenix (and, perhaps, Tucson) is most likely a significant load pocket, given transmission constraints in the region. In addition, APS already owns a significant fraction of all generation in the state. Thus, any additional ability on the part of APS to unjustifiably raise prices within Arizona will affect TEP's current ratepayers also, since retail competition has begun.

Impact of Negative Stranded Costs on Individual Generation Assets

Q. WHAT ARE STRANDED COSTS?

A. Annual stranded costs are defined as the difference between a utility's annual generation-related revenue requirements under traditional regulation, and the annual market value of that generation. Total stranded costs are defined as the net present value of the stream of annual stranded costs over the remaining lifetime of the utility's generation assets. Stranded costs can be positive or negative.

Q. HOW SHOULD NEGATIVE STRANDED COSTS FOR INDIVIDUAL GENERATION ASSETS BE TREATED?

A. The stranded cost amounts for all generation assets should be combined into one total, and that total should be recovered solely by the ratepayers if it is negative. If the total is positive, the appropriate manner to share recovery of stranded costs shall be litigated at the Commission.

Q. WHAT IS WRONG WITH TEP "BORROWING" THE STRANDED COSTS ASSOCIATED WITH GENERATION ASSETS THAT HAVE NEGATIVE STRANDED COSTS?

A. TEP should acquire capital for its new investments through the capital markets, not through "loans" from ratepayers such as that described at the end of the Settlement Agreement's section VI (page 4). If TEP is proposing to acquire capital this way, it is probably because a lender would consider the risk too high to justify a loan at TEP's target rate of return. This suggests the "loan" by ratepayers to TEP would be a bad risk. If TEP went bankrupt at any time during the long span before the loan is to be repaid, the ratepayers would have paid disproportionately more of the positive stranded costs than they had received of the negative stranded costs, and their future recovery of the negative stranded costs might be in jeopardy.

TEP Ownership of State-wide Transmission System

Q. SHOULD TEP EMBARK ON MAJOR NEW INVESTMENTS IN TRANSMISSION?

A. No, it is not likely that it would be in the public interest for TEP to significantly expand its transmission system investments. The Settlement Agreement states that "it is the intent of Staff and, by its approval of this Agreement, the Commission, that TEP's transmission company affiliate be the sole builder and owner of transmission assets in the state (page 7)." It also directs that TEP's transmission affiliate "will acquire all transmission facilities owned by TEP, APS, SRP, AEPCO and others."

TEP is already severely short of equity and impaired in its ability to raise capital, because of ongoing financial problems. It therefore seems poorly suited to the task of making and maintaining major new investments in transmission assets. This entire proposal requires much more flushing out and review by all parties before it can even be seriously considered by the Commission. This is especially true since the ACC does not even regulate the transmission systems of SRP and WAPA.

Q. WHAT IMPACT WOULD A TEP-OWNED TRANSCO STATEWIDE TRANSMISSION MONOPOLY HAVE ON THE COST OF TRANSMISSION IN ARIZONA?

A. This is difficult to predict, but there is an important reason why it might increase the cost of transmission to large parts of Arizona. Transco, TEP's transmission affiliate, would have a higher cost of capital than the current owners of many of the transmission facilities in

Arizona. This is true, in part, because TEP's past financial troubles increase the perceived risk of lending to a TEP affiliate, and in part because SRP and the cooperatives, current owners of some of Arizona's transmission assets, receive low-cost financing and certain tax treatments which reduce their cost of capital.

Waivers

Q. THE PROPOSED SETTLEMENT AGREEMENT HAS ALLOWED FOR WAIVERS FOR MANY OF THE ACC'S RULES FOR TEP. DO YOU HAVE ANY COMMENTS ON THE WAIVERS PROPOSED?

A. Yes. The Agreement proposes that waivers be granted for complying with R14-2-701, et seq., the Integrated Resource Planning Rules. To the extent that these waivers could apply to generation, then they could be granted. However, to the extent that the waivers would apply to future transmission (or distribution) system investments, then they should be denied. IRP procedures ought to continue to be applied to transmission investments using the projected market price for generation as the basis for doing least-cost transmission system planning.

In addition, the Agreement calls for a waiver from the Decision No. 59594 requirement that a Mid-Year DSM and Renewables Report be filed. I am not aware of why the restructuring process should cause the need for these reports to change. Similarly, a waiver should not be granted from the Decision No. 58497 requirements to file an avoided cost report. Even after divestiture is completed, there will be a market price for incremental supplies of power for different DSM-related load shapes. This information will still be useful to help ensure that new DSM investments are cost-effective.

Q. ARE THERE ANY OTHER WAIVERS THAT YOU ARE OPPOSED TO THE ACC GRANTING?

A. Yes. I oppose the granting of several other waivers which TEP has requested. Specifically, I object to the waiver of condition numbers 19, 20, 21, and 28 in Decision No. 60480.

Conditions 19, 20, and 21 restrict TEP's actions in certain ways, for the purpose of improving TEP's debt-heavy capital structure. TEP requests a waiver of these conditions, claiming that its capital structure will be dramatically redefined after divestiture. While divestiture would likely improve TEP's capital structure, it is premature to waive these conditions at this time After any Commission-authorized divestiture is completed, waiver of these conditions may be appropriate. However, it is premature to grant these waivers at this time.

Condition 28 prevents TEP's parent company and sister companies from investing amounts greater than $60 million in any single investment without Commission approval. This condition was also designed to protect TEP's customers from further deterioration of TEP's capital structure. The Commission may approve any such investment, but it is inappropriate to waive the condition in its entirety.

V. CONCLUSION

Q. ARE THE TWO PROPOSED SETTLEMENT AGREEMENTS AN IMPROVEMENT OVER APS' AND TEP'S ORIGINAL STRANDED COST RECOVERY FILINGS?

A. No. The proposed Settlement Agreements are worse for Arizonans because they correct none of the major problems of the original stranded cost filings, while they create many new problems. Many of these new proposals and problems could lead to higher electricity prices in Arizona than need be the case. In summary, the proposed Settlement Agreements would not lead to retail competition, especially for small customers. They would very likely over-charge customers for stranded costs, they would over-charge customers for their Standard Offer rates, and they would very likely lead to greater market power on the part of APS. Because the two proposed Settlement Agreements leave so many problems either unsolved or insufficiently addressed, they both should be rejected by the Commission This is especially necessary in light of the insufficient time which most parties to these dockets have had to properly analyze the numerous new issues raised by the proposed Agreements.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Attachment FB-2

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF	)	
COMPETITION IN THE	)	
PROVISION OF ELECTRIC	)	**DOCKET NO. U-0000-94-165**
SERVICES THROUGHOUT	)	
THE STATE OF ARIZONA	)	

DIRECT TESTIMONY OF

DR. RICHARD A. ROSEN

Submitted on Behalf of
The Residential Utility Consumer Office

January 21, 1997

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LIST OF EXHIBITS

D. Unbundling Results for APS, SRP and TEP

Q. DID YOU USE THE TELLUS UNBUNDLIGN METHODOLOGY TO DEVELOP ESTIMATES OF THE UNBUNDLED REVENUES FOR APS, TEP, AND SRP?

A. Yes, I did.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR APS?

A. The unit unbundled revenues for APS were as follows:

- Generation - 5.02 cents per kWh
- Transmission - 0.59 cents per kWh
- Distribution - 2.06 cents per kWh
- Customer - 0.38 cents per kWh.

The total average retail rate was 8.05 cents per kWh.

Q. WHAT WERE THE UNBUNDLED GENERATION, TRANSMISSION, DISTRIBUTION AND CUSTOMER REVENUE RESULTS FOR TEP?

A. The unit unbundled revenues for TEP were as follows:

- Generation - 6.12 cents per kWh
- Transmission - 0.83 cents per kWh
- Distribution - 1.32 cents per kWh
- Customer - 0.29 cents per kWh.

The total average retail rate was 8.55 cents per kWh.

Summary of Stranded Costs Estimates

Net Present Value of Stranded Costs (1996-2010)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	836	1198	42
High Market Price	411	1051	-440
Low Market Price	1211	1345	526

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Net Present Value of Stranded Costs (1998-2012)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	102	779	-834
High Market Price	-417	599	-1433
Low Market Price	559	959	-233

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Net Present Value of Stranded Costs (1998-2020)
(million 1998$)

Scenario	Company		
	APS*	TEP	SRP
Base Case	-838	513	-3009
High Market Price	-1578	257	-3927
Low Market Price	-186	770	-2090

*Note: Stranded Costs for APS accounts for generation-related assets not in rates ($110.3 million).

Cost Components of a Retail Generation Services Adder[1]
(mills per kWh)
Arizina Public Service Company (APS) & Tucson Electric Power Company (TEP)

Sources	Cost Component	Small Customers[2]		Large Customers	
		- low case -	- high case -	- low case -	- high case -
1	Generation-related customer services	1.1	2.2	0.5	1.0
2	Other ancillary services not in current A&G	0.0	1.0	0.0	1.0
3	Generation-related A&G	5.0	5.0	5.0	5.0
4	Marketing and advertising	1.1	2.2	0.5	1.0
5	Subtotal	7.2	10.4	6.0	8.0
6	Profit	0.7	1.0	0.3	0.4
7	Income tax	0.3	0.4	0.1	0.1
8	Total	8.2	11.8	6.4	8.5

Weighted Average Retail Generation Services Adder Across Customer Classes
APS & TEP– FERC Form 1 Data

1996 Sales	Small Customers		Large Customers	
Residential Sales (MWH)		10,057,722		0
Commercial Sales (MWH)		9,540,588		0
Industrial Sales (MWH)		0		6,406,035
Total Sales to Ultimate Customers (MWH)		19,598,310		6,406,035
	- low case -	- high case -	- low case -	- high case -
Weighted Average Adder	7.7	11.0	7.7	11.0

Footnotes:

1. These retail adders are not intended to be estimates of appropriate "generation credits" for the purpose of stimulating competition in a pilot program.
2. Assumes a consumption of 917 kWh per month, average over APS and TEP small customers.

Sources

1. Billing and collection services, customer inquiries, etc.
2. Refer to Exhibit___(RAR-2) for a listing of these ancillary services.
3. APS: actual cost embedded in its average retail rate.
4. N.H. PUC set 3.7 mills per kWh in the N.H. pilots, based on expenditures of $44 per small customer (500 kWh per month) over two years.
5. Subtotal of lines 1-4
6. Profit = 10% of retail adder
7. Income tax = 35% of profit
8. Total of lines 5-7

Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.10	3.10	6,986	216.4
1998	2.65	2.65	7,122	188.5
1999	2.13	2.13	7,261	154.4
2000	1.53	1.53	7,403	113.3
2001	1.39	1.39	7,548	105.1
2002	1.25	1.25	7,695	96.4
2003	1.11	1.11	7,846	86.9
2004	0.96	0.96	7,999	76.6
2005	0.80	0.80	8,155	65.6
2006	0.65	0.65	8,315	53.7
2007	0.48	0.48	8,477	40.9
2008	0.31	0.31	8,643	27.2
2009	0.14	0.14	8,812	12.5
2010	(0.04)	(0.04)	8,984	(3.3)
2011	(0.22)	(0.22)	9,159	(20.2)
2012	(0.41)	(0.41)	9,338	(38.2)
2013	(0.60)	(0.60)	9,521	(57.5)
2014	(0.80)	(0.80)	9,707	(78.1)
2015	(1.01)	(1.01)	9,897	(100.0)
2016	(1.22)	(1.22)	10,090	(123.4)
2017	(1.44)	(1.44)	10,287	(148.3)
2018	(1.67)	(1.67)	10,488	(174.9)
2019	(1.90)	(1.90)	10,693	(203.1)
2020	(2.14)	(2.14)	10,902	(233.1)

Net Present Value of Stranded Costs (1996-2010) (1998$)[2]:	**$1,197.8**
Net Present Value of Stranded Costs (1998-2012) (1998$)[2]:	**$778.9**
Net Present Value of Stranded Costs (1998-2020) (1998$)[2]:	**$513.4**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (1998-2020) (1998$)	**$513.4**

Assumed utiltiy nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year.
	CC/CT Mix Method in Year Excess Capacity Ends
	See Table 4: Scenario Assumptions
Escalation Rates:	
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.02	6.12	0.00
1998	3.47	6.12	0.00
1999	3.99	6.12	0.00
2000	4.59	6.12	0.00
2001	4.73	6.12	0.00
2002	4.87	6.12	0.00
2003	5.01	6.12	0.00
2004	5.16	6.12	0.00
2005	5.32	6.12	0.00
2006	5.48	6.12	0.00
2007	5.64	6.12	0.00
2008	5.81	6.12	0.00
2009	5.98	6.12	0.00
2010	6.16	6.12	0.00
2011	6.34	6.12	0.00
2012	6.53	6.12	0.00
2013	6.72	6.12	0.00
2014	6.93	6.12	0.00
2015	7.13	6.12	0.00
2016	7.34	6.12	0.00
2017	7.56	6.12	0.00
2018	7.79	6.12	0.00
2019	8.02	6.12	0.00
2020	8.26	6.12	0.00

[1] All costs are in nominal dollars.

Table 2: Unbundling Analysis of Historical Costs - 1996
Tucson Electric Power Company
(thousand dollars)

Category	Total Cost	Cost Components			
		Generation	Transmission	Distribution	Customer
O&M Expenses:					
Production	$339,092	$339,092			
O&M Minus Fuel	$135,991	$135,991			
Fuel	$203,102	$203,102			
Transmission	$6,894		$6,894		
Distribution	$12,284			$12,284	
Customer/Sales	$14,501				$14,501
Subtotal	$372,771	$339,092	$6,894	$12,284	$14,501
A&G[1]	$59,943	$48,044	$2,436	$4,340	$5,123
Total	$432,714	$387,136	$9,330	$16,624	$19,624
Plant Related Costs:					
Depreciation and Amort.	$76,229	$38,188	$17,533	$20,508	$0
Net Interest	$103,096	$49,431	$23,867	$29,799	$0
Net Income	$11,982	$5,745	$2,774	$3,463	$0
Income Taxes[2]	$9,892	$4,743	$2,290	$2,859	$0
Other Taxes[3]	$37,604	$18,030	$8,705	$10,869	$0
Residual[4]	$21,514	$10,315	$4,980	$6,218	$0
Total	$260,317	$126,452	$60,149	$73,716	$0
Total Operating Revenues[5]	$693,031	$513,588	$69,479	$90,341	$19,624
less Wholesale Revenues	($106,945)	($94,201)	($12,744)	$0	$0
Total Retail Revenues	$586,087	$419,387	$56,735	$90,341	$19,624
Total Retail Sales (MWH)	6,851,706				
Average Retail Rate (cents/kWh)	8.55	6.12	0.83	1.32	0.29

Footnotes:

1 A&G Costs are allocated to Generation, Transmission, Distribution, and Customer cost components based on the following percentages: 80.2%, 4.1%, 7.2%, and 8.5%.

2 Income Taxes include Federal Income Taxes, Other Incomes Taxes, ~~Provision for~~ Deferred Income Taxes (incl. credits).

3 Other Taxes are those classified by DOE/EIA as "taxes other than income taxes." For purposes of this analysis, state sales taxes, if applicable, are deducted from Other taxes since these taxes will be levied regardless of industry structure.

4 Residual is set so that total O&M Expenses plus Plant Related Costs equal Total Operating Revenues (net of sales taxes).

5 Total Operating Revenues do not include revenues collected from state sales taxes.

Table 1: Market Price Calculation for Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power

(1) Using Least Cost Mix of Combined Cycle and Combustion Turbine:

Real Levelized Fixed Charge Factor: 10.88%

Combined Cycle:	Total Costs:	1996 Real Levelized Costs
Capital Costs	383.0 $/kW	0.79 ¢/kWh
Fixed O&M	11.7 $/kW-yr	0.22 ¢/kWh
Variable O&M	0.23 mills/kWh	0.02 ¢/kWh
Fuel	1.97 ¢/kWh	1.71 ¢/kWh
	Sum of Levelized Costs:	*2.74 ¢/kWh*
	Levelized Capacity Costs:	*53.4 $/kW-yr*

Combustion Turbine:	Total Costs:	1996 Real Levelized Costs
Capital Costs	275.0 $/kW	29.47 ¢/kWh
Fixed O&M	9.4 $/kW-yr	9.26 ¢/kWh
Variable O&M	0.10 mills/kWh	0.01 ¢/kWh
Fuel	3.61 ¢/kWh	3.13 ¢/kWh
	Sum of Levelized Costs:	*41.86 ¢/kWh*
	Levelized Capacity Costs:	*39.3 $/kW-yr*

Capacity Factor Crossover for CC/CT		11%
Percent of CC energy in Market Price		99.6%
Percent of CT energy in Market Price		0.4%
Average Price of CC/CT mix		**2.91 ¢/kWh**
T&D Line Loss Adjustment	10%	0.30 ¢/kWh
Order 888 Ancillary Services		0.10 ¢/kWh
Retailing A&G Adjustment		0.50 ¢/kWh
Other Retailing Costs Adjustment		0.27 ¢/kWh
Adjusted Retail Market Price based on CC/CT mix		**4.08 ¢/kWh**
Year Excess Capacity Ends		**2000**

(2) Using Capacity Charge and Energy Charge:

Capacity Charge ($/kW-yr):	**NA**	
Energy Charge (¢/kWh):	**NA**	
Average Market Price for Electricity:		**none ¢/kWh**

(3) Using an Exogenous Value:

User-Input Wholesale Market Price for Electricity		**1.59 ¢/kWh**
T&D Line Loss Adjustment	10%	**0.17 ¢/kWh**
Order 888 Ancillary Services		**0.10 ¢/kWh**
Retailing A&G Adjustment		**0.50 ¢/kWh**
Other Retailing Costs Adjustment		**0.27 ¢/kWh**
User-Input Retail Market Price for Electricity		**2.63 ¢/kWh**

Table 4
Assumptions Used in Estimating Stranded Costs for Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power
Retail Adder equals 7.7 mills

I. Inputs for the RGS Market Price Calculation Based on CC/CT Optimal Mix:

Financial Assumptions:	
Real Discount Rate =	7.28%
Inflation Rate =	3.00%
Private Nom. Disc. Rate =	10.50%
Real Levelized FCF =	10.88%
Reserve Margin =	15%

Fuel Price Forecast (1996$/MMBtu):		User-Input			
1996	$3.03	2004	$2.68	2012	$2.75
1997	$2.11	2005	$2.72	2013	$2.71
1998	$2.27	2006	$2.73	2014	$2.73
1999	$2.32	2007	$2.73	2015	$2.75
2000	$2.36	2008	$2.73	2016	$2.80
2001	$2.39	2009	$2.71	2017	$2.85
2002	$2.48	2010	$2.71	2018	$2.90
2003	$2.59	2011	$2.72	2019	$2.95
				2020	$3.00

Souce: Exhibit_(RAR-6)

Combined Cycle:		
Capital Cost	383.0	1996$/kW
Fixed O&M	11.7	1996$/kW/yr
Var O&M	0.200	1996mills/kW
Heat Rate	6.500	Btu/kWh

Schnitzer, in Docket #16705, Direct Testimony on behalf of TX OPUC, and EIA Annual Energy Outlook 1997

Combustion Turbine:		
Capital Cost	275.0	1996$/kW
Fixed O&M	9.4	1996$/kW/yr
Var O&M	0.100	1996mills/kW
Heat Rate	11.900	Btu/kWh

Tellus Institute. Energy Innovations- A Prosperous Path to a Clean Environment (June 1997)

Cross-Over Calculation:

LOAD FACTOR	57%
Max. Annual Load (MW)	1619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1862
Cut-off point:	11.0%
Load at above Cut-off (MW)	1527
Total Energy under Load Curve (MWh)	10,513,248
Energy Supplied by CTs (MWh)	44,397
Energy Supplied by CCs (MWh)	10,468,851
Percentage of Energy Supplied by CTs	0.4%
Percentage of Energy Supplied by CCs	99.6%

Month-1996	Total Monthly Energy (MWh)	Monthly Non-Req. Sales for Resale & Losses (MWh)	Net Energy (MWh)	Monthly Peak (MW)
Jan	855,793	261,591	594,202	1,062
Feb	763,804	224,230	539,574	1,043
Mar	806,714	236,376	570,338	961
Apr	836,467	249,242	587,225	1,255
May	920,007	212,419	707,588	1,410
Jun	992,763	213,336	779,427	1,519
Jul	1,144,033	262,289	881,744	1,619
Aug	1,131,929	276,469	855,460	1,608
Sep	1,012,034	307,068	704,966	1,369
Oct	1,032,968	378,436	654,532	1,355
Nov	942,033	383,554	558,479	987
Dec	994,999	373,905	621,094	1,102
TOTAL	11,433,544	3,378,915	8,054,629	1,619

Utility FERC Form 1 Data

Average Wholesale Market Price of Electricity Based	29.09	$/MWh
on CC/CT Method	2.91	c/kWh
T&D Line Loss Adjustment	0.30	c/kWh
Order 888 Ancillary Services	0.10	c/kWh
Retailing A&G Adjustment	0.50	c/kWh
Other Retailing Costs Adjstmt	0.27	c/kWh

II. Other Market Price Options:

Capacity/Energy Charge:		
Capacity Charge	NA	$/MW
Energy Charge	NA	c/kWh
User-Input Retail Market Price:	2.63	c/kWh

CC-CT Market Price Worksheet for: Tucson Electric Power Company

Utility Load Data:

For eacn utility, a load profile for one year must be entered below. This data can be found in the utility's FERC Form 1, pg. 401. The areas in BLUE are the values which must be entered by the user

Month	Total Monthly Energy (MWh) USER-INPUT	Monthly Non-Requirements Sales for Resale & Associated Losses (MWh) USER-INPUT	Net Energy (MWh)	Monthly Peak (MW) USER-INPUT	Min. Monthly Load (MW)	Load Factor for Min. Monthly Load	Effective Min. Monthly Load (MW)
Jan	855,793	261,591	594,202	1,062			
Feb	763,804	224,230	539,574	1,043			
Mar	806,714	236,376	570,338	961	961	81%	781
Apr	836,467	249,242	587,225	1,255			
May	920,007	212,419	707,588	1,410			
Jun	992,763	213,336	779,427	1,519			
Jul	1,144,033	262,289	881,744	1,619			
Aug	1,131,929	276,469	855,460	1,608			
Sep	1,012,034	307,068	704,966	1,369			
Oct	1,032,968	378,436	654,532	1,355			
Nov	942,033	383,554	558,479	987			
Dec	994,999	373,905	621,094	1,102			
TOTAL	11,433,544	3,378,915	8,054,629	1,619	961	0.81	781

LOAD FACTOR	57%
Max. Annual Load (MW)	1,619
Min. Monthly Peak (MW)	961
Load Factor for Min. Monthly Load	0.81
Effective Min. Annual Load	781
Max. Load + Reserve Margin (MW)	1,862
Cut-off point:	11%
Load at above Cut-off (MW)	1,527

ratio between total energy under load curve and total monthly energy	0.92

Total Energy under Load Curve (MWh)	10,513,248		
Energy Supplied by CTs (MWh)	44,397	Ratio of energy supplied by CTs	0.4%
Energy Supplied by CCs (MWh)	10,468,851	Ratio of energy supplied by CCs	99.6%
check	0		

CC									
Capital Cost	41.67	$/kW times	1,527	MW	equals	63,624,506	dollars	$ 27.43	MWh
Fixed O&M	11.70	$/kW times	1,527	MW	equals	17,864,161	dollars		
Var O&M	0.20	mills/kWh times	8,020,614	MWh	equals	1,604,123	dollars		
Fuel	1.71	cents/kWh times	8,020,614	MWh	equals	136,950,332	dollars		
CT									
Capital Cost	29.92	$/kW times	335	MW	equals	10,023,160	dollars	$ 418.61	MWh
Fixed O&M	9.40	$/kW times	335	MW	equals	3,148,987	dollars		
Var O&M	0.10	mills/kWh times	34,015	MWh	equals	3,401	dollars		
Fuel	3.13	cents/kWh times	34,015	MWh	equals	1,063,294	dollars		
					TOTAL	234,281,965	dollars		
					Tot Energy in real LDC	8,054,629	MWh		

OUTPUT

Average Market Price of Electricity - 1996

29.09	$/MWh
2.91	c/kWh

Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.06	3.06	6,986	213.8
1998	2.56	2.56	7,122	182.4
1999	1.98	1.98	7,261	143.6
2000	1.30	1.30	7,403	96.3
2001	1.16	1.16	7,548	87.3
2002	1.01	1.01	7,695	77.6
2003	0.86	0.86	7,846	67.2
2004	0.70	0.70	7,999	56.0
2005	0.54	0.54	8,155	43.9
2006	0.37	0.37	8,315	30.9
2007	0.20	0.20	8,477	17.0
2008	0.02	0.02	8,643	2.1
2009	(0.16)	(0.16)	8,812	(13.9)
2010	(0.34)	(0.34)	8,984	(31.0)
2011	(0.54)	(0.54)	9,159	(49.2)
2012	(0.74)	(0.74)	9,338	(68.7)
2013	(0.94)	(0.94)	9,521	(89.5)
2014	(1.15)	(1.15)	9,707	(111.7)
2015	(1.37)	(1.37)	9,897	(135.3)
2016	(1.59)	(1.59)	10,090	(160.5)
2017	(1.82)	(1.82)	10,287	(187.2)
2018	(2.06)	(2.06)	10,488	(215.7)
2019	(2.30)	(2.30)	10,693	(246.0)
2020	(2.55)	(2.55)	10,902	(278.1)

Net Present Value of Stranded Costs (1996-2010) (1998$)[2]:	**$1,050.9**
Net Present Value of Stranded Costs (1998-2012) (1998$)[2]:	**$599.1**
Net Present Value of Stranded Costs (1998-2020) (1998$)[2]:	**$257.2**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (1998-2020) (1998$)	**$257.2**

Assumed utiltiy nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year, CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	3.06	6.12	0.00
1998	3.56	6.12	0.00
1999	4.14	6.12	0.00
2000	4.82	6.12	0.00
2001	4.96	6.12	0.00
2002	5.11	6.12	0.00
2003	5.26	6.12	0.00
2004	5.42	6.12	0.00
2005	5.58	6.12	0.00
2006	5.75	6.12	0.00
2007	5.92	6.12	0.00
2008	6.10	6.12	0.00
2009	6.28	6.12	0.00
2010	6.47	6.12	0.00
2011	6.66	6.12	0.00
2012	6.86	6.12	0.00
2013	7.06	6.12	0.00
2014	7.27	6.12	0.00
2015	7.49	6.12	0.00
2016	7.71	6.12	0.00
2017	7.94	6.12	0.00
2018	8.18	6.12	0.00
2019	8.42	6.12	0.00
2020	8.67	6.12	0.00

[1] All costs are in nominal dollars.

Table 3b: Projecting Future Costs for
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Year	Stranded Costs (cents/kWh)	Shared Stranded Costs (cents/kWh)	System Gen.[1] (GWh)	Stranded Costs ($ million)
1996	3.49	3.49	6,852	239.2
1997	3.14	3.14	6,986	219.1
1998	2.73	2.73	7,122	194.7
1999	2.28	2.28	7,261	165.4
2000	1.76	1.76	7,403	130.3
2001	1.63	1.63	7,548	123.0
2002	1.50	1.50	7,695	115.1
2003	1.36	1.36	7,846	106.5
2004	1.22	1.22	7,999	97.3
2005	1.07	1.07	8,155	87.2
2006	0.92	0.92	8,315	76.4
2007	0.76	0.76	8,477	64.8
2008	0.60	0.60	8,643	52.3
2009	0.44	0.44	8,812	38.8
2010	0.27	0.27	8,984	24.3
2011	0.10	0.10	9,159	8.9
2012	(0.08)	(0.08)	9,338	(7.7)
2013	(0.27)	(0.27)	9,521	(25.5)
2014	(0.46)	(0.46)	9,707	(44.5)
2015	(0.65)	(0.65)	9,897	(64.7)
2016	(0.86)	(0.86)	10,090	(86.4)
2017	(1.06)	(1.06)	10,287	(109.4)
2018	(1.28)	(1.28)	10,488	(134.0)
2019	(1.50)	(1.50)	10,693	(160.2)
2020	(1.73)	(1.73)	10,902	(188.1)

Net Present Value of Stranded Costs (1996-2010) (1998$)[2]:	**$1,345.2**
Net Present Value of Stranded Costs (1998-2012) (1998$)[2]:	**$958.9**
Net Present Value of Stranded Costs (1998-2020) (1998$)[2]:	**$770.0**
Net Present Value of Generation-Related Reg. Assets Not in Rates	**$0.0**
Net Present Value of Total Stranded Costs (1998-2020) (1998$)	**$770.0**

Assumed utiltiy nominal discount rate	**7.75%**

Table 3a: Projections of Stranded Costs[1]
Tucson Electric Power Company
Scenario: Base year wholesale price based on average price of purchased power, Retail Adder equals 7.7 mills

Assumptions:

RGS market prices are based on:	User Exogenous Input in Base Year. CC/CT Mix Method in Year Excess Capacity Ends
Escalation Rates:	See Table 4: Scenario Assumptions
O&M Costs	3.0%
Year when excess capacity ends:	2000

Year	RGS Market Price (cents/kWh)	RGS Regulated Price (cents/kWh)	Transition Charge (cents/kWh)
1996	2.63	6.12	0.00
1997	2.98	6.12	0.00
1998	3.39	6.12	0.00
1999	3.84	6.12	0.00
2000	4.36	6.12	0.00
2001	4.49	6.12	0.00
2002	4.63	6.12	0.00
2003	4.76	6.12	0.00
2004	4.91	6.12	0.00
2005	5.05	6.12	0.00
2006	5.20	6.12	0.00
2007	5.36	6.12	0.00
2008	5.52	6.12	0.00
2009	5.68	6.12	0.00
2010	5.85	6.12	0.00
2011	6.02	6.12	0.00
2012	6.20	6.12	0.00
2013	6.39	6.12	0.00
2014	6.58	6.12	0.00
2015	6.77	6.12	0.00
2016	6.98	6.12	0.00
2017	7.18	6.12	0.00
2018	7.40	6.12	0.00
2019	7.62	6.12	0.00
2020	7.85	6.12	0.00

[1] All costs are in nominal dollars.

Tellus Institute
Strandable Costs Calculation Model

1. Introduction

This document serves as a guide to the Tellus Institute approach to calculating strandable costs for an electric utility. It provides an overview of the methodology, inputs, and scenario development used in calculating utility-specific strandable costs. To facilitate the strandable costs calculation, a simple model was developed consisting of four interdependent analyses: an unbundling analysis, a market price analysis, a financial evaluation of strandable costs in a single year, and a projection of strandable costs over a specified period of analysis. Since each utility faces a unique set of circumstances entering into the competitive generation market, the Tellus Strandable Costs Model (SCM) is designed to provide an analysis of the specific financial conditions for each utility.

It is important to recognize that any estimates of strandable costs will include many uncertainties, and will be subject to debate by many parties. Therefore, estimates of strandable costs should be as simple and as clear as possible. This information guide is intended to explain Tellus' SCM modeling assumptions and should assist readers in following the logic of the calculations in the model. In addition, Tellus recommends that SCM estimates should be prepared for a variety of scenarios and sensitivities to indicate how the stranded costs might change with different input assumptions.

2. Methodology

Strandable costs can generally be defined as the difference between the competitive market value and the regulated book value (or embedded cost value) of a utility's generation assets. Therefore, the general approach to estimating strandable costs is to calculate the difference between (a) the utility's embedded generation cost value over a specified period of time, and (b) the market price for power in the region over the same period of time. The SCM follows from this basic equation. As such, the SCM calculates a utility's *potentially strandable* costs, as opposed to costs that would actually be stranded (e.g., as a result of customers actually leaving the utility's system for an alternative supplier). Strandable costs represents the maximum amount of costs that may become stranded in a retail competitive generation market.

The SCM includes four main components: a market price calculation; an unbundling calculation of the utility's average retail generation price; a calculation of strandable costs in the base year; and a projection of strandable costs over a user specified period of analysis.

Market Price Calculation

The user can choose from three different methods to determine the average generation market price value for the first year of analysis, based on: 1) a least cost mix of new natural gas combined cycle and combustion turbine generating units; 2) user-specified capacity and energy charges; or 3) an exogenous user-input value. In all cases, the estimate of market price is based on the assumption that competitive generation companies in the utility's region provide energy sufficient to meet the utility's entire load. In other words, the market price represents the average cost of power in the region, as opposed to the marginal cost.

The first option derives a competitive market price based on the cost of an optimal combination of new natural gas combined cycle and combustion turbine units. This method requires the user to make assumptions about current and future fuel (gas) prices, a discount rate, and fixed charge factor. A real levelized average market price based on this CC/CT mix represents the market price for the first year of analysis.

For the second option, the competitive market price is based on user-specified energy and capacity charges. Specific energy and capacity price information could be based on existing state or regional market price proxy values, such as competitive wholesale prices, avoided cost values, etc.

Finally, the user has the option of simply entering an exogenous, average market price value.

Unbundled Generation Costs

The user enters utility-specific costs and revenues for a historical year using information provided by utilities to FERC. Unbundled costs are calculated by allocating the data into generation, transmission, distribution, and customer related expenses, according to FERC accounting categories. After the expenses and revenues are spread among these categories, further adjustments are made regarding wholesale transactions to produce a final estimate of embedded costs per category. An average unbundled rate (in cents/kWh) for each component is then computed by dividing embedded costs by ultimate sales to customers.

Strandable Costs - Base Year

Strandable costs for the first year of analysis are calculated based on a comparison of the utility's unbundled generation rate and the assumed market price. The user has the option of assuming a transition charge, which allows the utility to recover from customers a portion of stranded costs. The "net" revenue reduction represents the strandable costs, less any revenues recovered through the transition charge. The utility's net revenue reduction is then compared to how it will impact the utility's shareholders, as well as its average retail customer.

Strandable Cost - Projections

Finally, the SCM allows the user to develop scenario projections based on a fixed time horizon (not to exceed 10 years). The method for determining the market price over the projected time period will depend on whether or not the utility has excess capacity, and if that excess capacity is anticipated to end during the period of the analysis. If the utility does have excess capacity which is expected to end within the period of analysis, then regardless of what method is used to calculate market price in the base year, the model will automatically switch to the CC/CT Mix market price in the year that excess capacity ends, since this price will best represent the marginal cost of generation in the future. In that year, the CC/CT Mix market price will reflect a price that is escalated from the base year CC/CT Mix price according to user's assumed escalation rates for fuel, energy and fixed cost components.

Regardless of which market price methodology is used, the user can make assumptions about escalation rates for the various market price components (e.g., energy and demand charges). The user may also choose to enter an escalation rate for the utility's average unbundled generation price projection. And finally, the user may estimate the utility's future electricity sales either by entering a forecast of sales over the projection period or by escalating the base year sales at a specified rate.

The computation and inputs for the SCM are discussed in greater detail below.

3. Inputs and Computational Analysis

The inputs necessary to calculate strandable costs will come from a number of utility-specific and industry-specific sources. Examples of such sources are: the utility's FERC FORM 1, current utility Integrated Resource Plans and Annual Reports, and various fuel cost forecasts, and supply and demand forecasts for the region.

Unbundling Generation Costs

The first step in the valuation of a utility's existing generation assets is to isolate those costs and revenues which are associated with generation-related assets. To do this, the models' unbundling input spreadsheet requires that information from the utility's Operating Income (FERC FORM 1 pp. 114-119), Electric Operation and Maintenance Expenses (FERC FORM 1 pp. 320-323), Customer Sales and Operating Revenues (FERC FORM 1 pp. 300-304), and Electric Utility Plant (FERC FORM 1 pp. 220-221) be entered as inputs.

The model uses a simple method to unbundle these costs and revenues by allocating the Operation & Maintenance Expenses, Plant Related Expenses, and Operating Revenues in rate base into generation-related, transmission-related, distribution-related and customer-related costs and revenues, according to each category's contribution to net plant (or gross plant in the case of depreciation). In the case of Administrative and General Expenses, the user has the option to directly allocate these costs to any of the four cost components.

Total Operating Revenues represent the value of assets in rate base, for both wholesale and retail operations. In order to obtain the utility's total *retail* revenues, a wholesale revenue adjustment must be made to Total Operating Revenues. The Adjusted Retail Revenues are then converted to an average retail rate (cents/kWh) per cost component by dividing the totals by total retail sales. The final result is an estimate of unbundled generation, distribution, transmission, and customer costs for the utility's retail operations.

Market Price

Estimating a competitive market price for a specific state or region is likely to be highly uncertain. In order to accommodate different levels of information about the market price for power, the model allows for three market price options to be pursued and examined in separate scenarios.

As discussed earlier, the first option utilizes cost information for a newly built Combustion Turbine (CT) and a newly built Combined Cycle (CC) plant to determine a market price based on the optimal mix of CTs and CCs to serve the utility's load profile. This estimation of market price is likely to represent a "high" market price value. The model offers the user the option to input plant-related cost information for a new CC or CT, or to simply use the default values provided from the *EPRI Technical Assessment Guide*. In addition, financial assumptions such as the fixed charge factor, and fuel cost escalation and inflation rates may be input or default values may be used.

To determine the likely future mix of CCs and CTs for a utility's system, the SCM conducts a crossover calculation, based on a comparison of fixed and variable costs, to determine the capacity factor below which CTs will operate and above which CCs will operate. The outcome of the crossover calculations provides the combination of CCs and CTs which would serve this utility's system at the lowest cost, optimal or least cost system. In order to correctly compare the unbundled generation rate to the CC/CT market price in the strandable costs comparison, it is necessary to adjust the CC/CT market price to reflect the generation-related A&G costs the utility would likely incur in providing this electricity, just as they are reflected in the unbundled generation rate. The amount of the CC/CT market price A&G adjustment is based on the historical cost of generation related A&G, as reflected in the unbundling spreadsheet.

The second market price option allows for the choice of representative energy and demand charges to be input. Using these charges, along with the utility's load data, the model calculates the average market generation price in costs/kWh. Using this method, the user can create a range of high, medium, and low market prices assumptions that are derived from a range of user input energy and demand charges.

The third market price option simply allows the user to directly input a market generation price (in cents/kWh). Again, with this straightforward method, the user can create a range of market price assumptions.

Strandable Costs - Base Year

Once the unbundled generation costs for the utility have been estimated by the model, and a market price has been estimated, strandable costs for the base year can be calculated as the difference between the two. The model presents the output for a one year strandable cost calculation. The model calculates the net reduction in generation costs (in ¢/kWh) as the difference between the average utility generation cost and the competitive market price. If a transition charge is assumed, then the net reduction in generation costs will be reduced accordingly. Finally, retail sales are used to determine the strandable costs (i.e., revenue reduction) in this one year.

In turn, the model examines the impact on the shareholders by examining the Revenue Reductions due to competition as a percentage of the following costs:

- Net Income plus Income Taxes (or Gross Income)
- Gross Income plus Depreciation
- Gross Income plus Depreciation and Net Interest.

The first comparison is likely the most important, since the financial viability of a utility is typically measured in terms of its ability to pay its shareholders and its income taxes. A scenario in which there would be a sharing of stranded costs (e.g., using a transition charge) would clearly alleviate the impact on shareholders, yet not provide as a large reduction in the average generation rate to ratepayers.

4. Strandable Costs - Projections

The SCM allows for scenarios that calculate potential strandable costs over a multiple year period. The importance of analyzing this information is that while the first year may reveal significant initial strandable costs for a utility, the utility's strandable costs over a longer period of analysis may provide an entirely different picture. For example, a utility with stranded costs in the base year may, within a few years, face no strandable costs, and may even receive profits as a result of its embedded generation costs falling below expected future market prices.

In this multi-year period analysis, the user first selects the time period for the projection, and identifies the year that excess capacity, if it exists, is anticipated to end. If excess capacity is exhausted within the projection period, the CC/CT market price takes effect in at that point in time. If no new capacity is needed within the projection period, then the market price assumed in the base year is simply escalated over the period of analysis based on a user specified escalation rate.

Depending on the market price methodology, selected escalation rates must be entered:

- CC/CT mixed price: escalation rates for Fuel Costs, Capital Costs, and O&M costs.
- Energy and Capacity Charges: escalation rates for the energy and capacity charges.
- Exogenous market price: Escalation rate for the exogenous ¢/kWh market price.

In addition to market price escalation data, escalation rates can be applied to the utility's average retail generation price and its retail sales in the base year.

Once the model calculates the projection of strandable costs, the sum of the strandable costs stream is converted to net present value. In a final important step, an adjustment is made to reflect the net present value of the generation-related regulatory assets not yet in ratebase. The sum of the stream of strandable costs and the potentially strandable regulatory assets, both in terms of net-present value, is the total potential strandable costs.

Based on a series of assumptions about the future costs of fuel, the increase in the market price over time, and the option to consider a transition charge, a full range of strandable cost sensitivities may be examined.

Attachment FB-3

Comparison of Rates and Billing Information for
Standard Offer Customer and Direct Access Customer

Standard Offer Customer	**Service**	**Direct Access Customer**
Same	Transmission	Same
Same	Ancillary Services	Same
Same	Distribution ("wires")	Same
Same	CTC	Same
Same	Taxes	Same
Same	System Benefits	Same
Shopping Credit	Generation	Market-Based
Shopping Credit	Metering (ownership, installation & maintenance)	Market-Based
Shopping Credit	Meter Reading	Market-Based
Shopping Credit	Billing & Collection	Market-Based

c:\Commonwealth\misc\Standard.tbl

Attachment FB-4

BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
Commissioner - Chairman
RENZ D. JENNINGS
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY.	DOCKET NO. E-01933A-98-0471
IN THE MATTER OF THE FILING OF TUCSON ELECTRIC POWER COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1602 et seq.	DOCKET NO. E-01933A-97-0772
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01345A-98-0473
IN THE MATTER OF THE FILING OF ARIZONA PUBLIC SERVICE COMPANY OF UNBUNDLED TARIFFS PURSUANT TO A.A.C. R14-2-1601 et seq.	DOCKET NO. E-01345A-97-0773
IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-00000C-94-165 **DIRECT TESTIMONY OF JOHN G. PATON**

On Behalf of
TUCSON ELECTRIC POWER COMPANY

NOVEMBER 20, 1998

TABLE OF CONTENTS

I. Introduction And Purpose

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. John G. Paton. New Harbor. Inc.. 280 Park Avenue. East Tower. 27th Floor. New York. New York. 10017.

Q. WHAT IS NEW HARBOR. INC.?

A. New Harbor. Inc. ("NHI") is an investment bank that specializes in financial advisory services for the electric, gas and water industries. The firm was founded in June 1993 and is comprised of experienced investment bankers from First Boston. Kidder. Peabody. Lehman Brothers. Merrill Lynch. Morgan Stanley and Salomon Brothers. Its Managing Directors have accumulated over seventy years of experience in the investment banking and financial advisory industry, and have worked with almost every major electric and gas utility in the United States. Their collective work experience includes a broad range of assignments from strategic advisory, divestiture of assets, mergers and acquisitions, bankruptcy and out-of-court restructurings to project finance, equity research, and debt and equity financings.

Q. WHAT IS YOUR POSITION WITH NEW HARBOR, INC.?

A. I am currently a Managing Director. My responsibilities include directing and overseeing all aspects of investment banking transactions, primarily in the strategic and restructuring areas. These activities include transaction structuring, auction design, valuation, negotiations, etc.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR BUSINESS EXPERIENCE AS THE SAME PERTAIN TO YOUR POSITION.

A. I received a Bachelor of Mathematics degree in 1980 from Waterloo University in Kitchener-Waterloo, Ontario, Canada. I am a Chartered Accountant, having been admitted by the Canadian Institute of Chartered Accountants in 1982. I received Masters of Business Administration and Bachelor of Laws degrees in 1986 from the University of Western Ontario in London, Ontario. Canada.

I worked as a public accountant in the audit and tax area of a predecessor firm to Peat Marwick Mitchell in Toronto. Ontario. Canada from 1977 through 1982. After completing my graduate degrees in 1986. I joined Salomon Brothers Inc in New York City. While at Salomon Brothers. I was part of the Mergers and Acquisitions Group, specializing in electric

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and gas utilities business combination transactions, defense, restructurings and bankruptcy advisory.

I left Salomon Brothers in February of 1992 to join Barr Beatty Devlin and Co., a strategic financial advisory firm specializing in gas and electric utilities. In July 1993, Jay Beatty and I left Barr Beatty Devlin to form NHI.

Q. PLEASE DESCRIBE ANY OTHER BUSINESS EXPERIENCE OR BACKGROUND AS IT RELATES TO THE DIVESTITURE OF THE GENERATING ASSETS OF TUCSON ELECTRIC POWER COMPANY ("COMPANY" OR "TEP").

A. I have been involved in the auctioning of large generating stations on behalf of U.S. electric utilities preparing for the deregulation of the power supply function. I personally directed the auction of approximately ten thousand megawatts of gas-fired generating capacity on behalf of Southern California Edison Company. I am currently conducting the sale of the 1,340 MW Centralia, Washington coal-fired mine-mouth generating station on behalf of the eight investor-owned and municipal utility owners, in addition to several other yet to be publicly announced divestitures.

Q. PLEASE DESCRIBE ANY BUSINESS EXPERIENCE AND BACKGROUND RELATED TO ELECTRIC UTILITY DIVESTITURES.

A. During the course of my career, I have been involved in several major mergers, acquisitions, and restructurings in the utility business, including the Entergy/GSU and San Diego/SCEcorp combinations and the bankruptcy cases of Public Service Company of New Hampshire, Eastern Utilities Associates and its wholly-owned nuclear power subsidiary, and EUA Power Corporation. More recently, I have been involved in representations of El Paso Electric Company, for both its bankruptcy case and proposed merger with Central and Southwest Corporation, as well as the Official Committee of Unsecured Creditors of the Columbia Gas System, Inc., and PacifiCorp in its acquisition of PowerCor in Victoria, Australia.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The primary purpose of my testimony is to discuss the various methods of divestiture considered by TEP and the rationale behind the selection of sale by auction.

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II. What is the Preferred Method of Divestiture for Tucson Electric Power Company?

Q. WHAT ALTERNATIVE METHODS OF DIVESTITURE WERE EVALUATED BY NHI AND TEP?

A. NHI, in conjunction with TEP, evaluated a variety of possible means of divesting the generating assets of TEP, with due regard for factors such as certainty of computation of transition costs, maximization of proceeds, fairness, efficiency and rapidity, and impact upon the competitive market. Two fundamental divestiture strategies were considered:

- Asset sale through auction
- Asset sale through negotiated private transaction

Q. WHAT IS AN ASSET SALE THROUGH AUCTION?

A. An asset sale through auction is a method of divestiture that uses a staged bidding process and allows numerous potential purchasers to participate. In general, an auction is the method that will most likely reveal the market value of an asset because it tends to draw out the largest number of potential buyers.

In light of existing uncertainties regarding the operation of the new electricity market, different potential buyers may have widely varying views of future electricity prices and the development of a direct access market. This may lead to a wide range of values attributed to the generation assets by potential purchasers. It is therefore desirable to expand the pool of potential buyers, at least initially, in order to identify buyers who value the assets most highly. By identifying and soliciting buyers who value the assets most highly, TEP will maximize the proceeds received from a sale and minimize stranded costs.

In addition to maximizing price, an auction advances other objectives, such as fairness to ratepayers, shareholders, and potential buyers. Further, an auction provides greater likelihood of convincingly demonstrating to the Commission and to other interested parties the market value of these stations.

Q. WHAT IS AN ASSET SALE THROUGH NEGOTIATED PRIVATE TRANSACTION?

A. In an asset sale through a negotiated private transaction, TEP would contact a limited number of parties for each asset and attempt to negotiate a sale through those contacts. In some contexts, a negotiated sale with one or possibly a few potential buyers may be the only realistic alternative. This may be true, for example, where there are significant restrictions on the seller's ability to dispose of an asset, or where market circumstances are such that it is highly unlikely that more than one party would even be potentially interested in purchasing the asset. Because fewer potential buyers are involved in a negotiated sale compared to an auction, sometimes the process is easier to manage.

Q. WHAT ARE THE RELATIVE MERITS OF AN AUCTION AND A NEGOTIATED SALE?

A. So long as TEP believes that a pool of buyers exist to purchase its generating assets, the primary advantage of a negotiated sale is the manageability of the process. However, a carefully designed auction process need not preclude incorporating the more beneficial aspects of negotiation. The auction should draw out the largest number of potentially qualified and interested parties thereby ensuring the best sale price. To make the process most efficient, TEP will narrow the field of bidders based on the bidders' preliminary bid submittals. This narrowing will enable TEP to deal with a more manageable number of parties as time-intensive activities, such as on-site due diligence and discussion of contractual language, proceed. An important feature of a staged auction is that it enables multiple rounds of bidding, providing flexibility to respond to bidders' concerns as well as incentivizing bidders to increase their offers. If TEP, as the seller, is prohibited from engaging in such activities as part of the auction, this lack of flexibility might deter potential bidders from participating, and TEP might be prevented from selling the generating assets at the best price and other terms. Based upon these considerations, TEP believes that the auction process should retain considerable flexibility.

Q. WHY WAS THE AUCTION METHOD CHOSEN?

A. Both an auction sale and a negotiated sale are reasonable and justifiable methods of disposing of generating assets. NHI recommends TEP proceed with an auction sale because it is more likely to give TEP and the Commission the greatest measure of assurance regarding the consequences of the divestiture, to ensure the best price for the assets, to attract and satisfy the largest number of potential owners, and is the most consistent with the regulatory process.

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Q. IS THE TRANSCO PROPOSAL WITH ARIZONA PUBLIC SERVICE ("APS") A VIABLE METHOD FOR REALIZING FAIR MARKET VALUE FOR TEP'S SHARE IN THE NAVAJO AND FOUR CORNERS GENERATING STATIONS?

A. As I have discussed previously, a negotiated sale is a viable means of realizing the fair market value of generating assets. The Transco proposal between TEP and APS has some unique aspects, which make a negotiated sale a particularly appropriate method of divestiture for the Navajo and Four Corners assets. The transmission assets of APS are an integral part of TEP's plans to become the builder and owner of transmission assets in Arizona, and cannot be obtained from a broad market solicitation of bids. Also, divesting the generating assets and acquiring transmission assets in separate transactions would be a more time consuming process than having both parties agree to the Transco proposal at this time.

III. How Will the Auction Process Work?

Q. WHAT ARE THE GOALS OF THE AUCTION?

A. TEP, in consultation with NHI, has designed its auction procedures with a focus on the goals of efficiency and price maximization, as well as fairness to all interested parties. In order to expedite divestiture, TEP has developed a streamlined, staged approach that is intended to ensure a fair auction process while preserving sufficient flexibility to allow for the maximum possible competition among potential and actual bidders for the assets that are to be sold.

Q. WHAT IS THE PROPOSED SCHEDULE FOR THE AUCTION?

A. Although TEP must retain the flexibility to alter its schedule to reflect unanticipated events, an anticipated schedule has been established to auction TEP's generating assets. The Company plans to implement a five-phase auction process, which is summarized in the following timetable (all dates are estimates only):

Phase 1	Pre-auction marketing activities	through March 1999
	Preparation of selling memorandum	
	Preparation of assets for sale	
	Buyer prequalification	
Phase 2	Distribution of selling memorandum	April through June 1999
	Receipt and analysis of indications of interest	

	Selection of short list of bidders	
Phase 3	Due diligence for short list participants	July through September 1999
	Receipt of final bids	
	Selection of winning bidders	
Phase 4	Negotiation and Execution of Documents	October through November 1999
Phase 5	Final regulatory approvals	By January 1, 2001
	Closing	

The timetable set forth above is tentative, and assumes among other things, timely regulatory approvals and the removal of material asset contingencies.

Q. WHAT IS THE COMMISSION'S ROLE DURING THE AUCTION PROCESS?

A. The Commission will be kept informed during every phase. The auction has been designed to be as robust and transparent as possible. While the bids must be kept confidential to ensure the integrity of the auction. TEP and NHI believe that the Commission must be informed of the progress of the auction.

Q. WHAT IS EXPECTED TO TAKE PLACE AT EACH STAGE OF THE AUCTION PROCESS?

A. The auction process has been designed to ensure that all bidders have the same opportunity to evaluate and bid on the generating assets. Phase 1 of the process is ongoing and will continue during the Commission's review period for this filing up until the commencement of the actual auction (Phase 2). Phase 1 activities include gathering all of the information necessary for bidders to conduct their due diligence, which will include operating, financial, environmental, legal and technical information on the generating assets. During Phase 1, NHI will assist TEP in identifying and contacting potential purchasers. TEP will also prepare a press release directing bidders to contact New Harbor in order to be included in the process. Phase 2 is the stage where initial indications of interest are provided by bidders. Potential bidders will receive copies of the Confidentiality and Auction Protocol Agreements as well as be given or have access to due diligence materials. Following the initial review period in Phase 2, bidders will be asked to submit non-binding Indications of Interest. TEP with NHI will evaluate the Indications of Interest and select a "short list" of bidders to invite into Phase 3, to conduct more extensive due diligence on the assets. The Indications of Interest will be evaluated primarily on price, financing contingencies, financial wherewithal to complete the transaction and any necessary consents or approvals that could significantly delay a closing. Specific bidders will be invited to participate in Phase 3 and will be provided additional due diligence material, site tours, and management presentations in order to make final bids for the assets. Phase 3 will require a high level of resources and commitment from the invited bidders. At the end of Phase 3, the bidders will be required to submit their final bids. Upon receipt of the final bids by NHI and TEP, the auction will enter Phase 4 where the final bids will be evaluated on a similar basis to the Indications of Interest and winning bidders will be selected. Bidders will be required to be available to meet with TEP and NHI for final negotiations and contract execution. Phase 4 will conclude with documents executed between the winning bidders and TEP for the generating assets. In Phase 5, the last phase of the auction process, TEP will submit executed documents to the Commission for approval. The Commission will have the opportunity at this time to review the filings to satisfy itself that the auctions were done in a fair, diligent and professional manner. Any other regulatory approvals, such as FERC and the Federal Trade Commission, will be obtained in this last phase.

Q. WHAT HAPPENS AT THE CONCLUSION OF THE AUCTION?

A. The auction will actually be concluded at the end of Phase 4 when the winning bidders have executed documents for the purchase of the generating assets. At that time, Commission and regulatory approvals of the sales will be obtained. Furthermore, upon completion of the auction process, but prior to the actual sale and transfer of the assets, TEP will file appropriate form of transfer documents and proposed must-run contracts for approval by the Commission.

IV. What Are the Auction Protocols?

Q. WHAT IS THE PURPOSE OF THE AUCTION PROTOCOLS?

A. TEP and NHI have designed an auction process to attract a wide universe of qualified bidders which will result in a market determination of the value of the generation assets in a manner that is fair to the bidders, efficient in terms of time requirements and effective for TEP, its shareholders and ratepayers. The auction protocols provide potential bidders with the details of the auction process including: the auction methodology, tentative timetable, rules of conduct, bidding restrictions, methods of allowable communication, cost responsibility and the form of bid. The auction protocols will be contained in the Confidentiality and Protocols Agreement, which each potential bidder will be required to execute prior to participating in the auction process.

Q. WHAT IS INCLUDED IN THE CONFIDENTIALITY AND PROTOCOLS AGREEMENT?

A. In addition, to containing the auction protocols, the Confidentiality and Protocols Agreement will obligate the potential bidder, its affiliates and representatives to maintain as confidential, any information, documents, data or any other material provided by TEP ("Due Diligence Material") or analyses performed by the bidder. Any such Due Diligence Material and analyses may be used by the bidder solely for the purpose of evaluating the assets. Potential bidders will be required to treat as confidential any bid or related discussions it has with TEP. Destruction of Due Diligence Material shall be certified by an officer of the bidder. Due Diligence Material provided to participants in the auction will include, among other things, a selling memorandum, any third-party environmental or engineering reviews performed for TEP in conjunction with the auction, as well as environmental, operating and technical information and data. Such information may be made available in a data room or provided directly to the potential bidder.

Q. WHEN WILL THE CONFIDENTIALITY AND PROTOCOL AGREEMENT BE DISTRIBUTED?

A. The Confidentiality and Protocol Agreement will be distributed to potential bidders at the end of Phase 1. No potential bidder will receive a Selling Memorandum on which to base initial indications of interest until the Confidentiality and Protocol Agreement has been signed and returned to TEP.

V. What Are the Current Divestiture Plans of TEP?

Q. WHICH ASSETS ARE BEING DIVESTED?

A. Bidders will have an opportunity to bid on any or all of the following Assets:[1]

[1] TEP has entered into the Settlement Agreement with the Commission Staff which will exchange TEP's interest in the Four Corners and Navajo generating stations for the transmission assets of the Arizona Public Service Company.

(i) Springerville (100% interest)

(ii) Irvington (100% interest)

(iii) San Juan (TEP's 50% interest in each of Units 1 and 2); and

(iv) TEP's combustion turbines

TEP reserves the right to bundle, or to change the bundling of the assets. Bidders will be notified of any changes and appropriate adjustments will be made to the auction timetable, if necessary, to allow for a resubmission of bids reflecting revised bundling, or for any other reason.

The Assets will include Leasehold, as well as ownership interests. The divestiture will include all ancillary agreements, operating permits, real and personal property, inventory and spare parts required to operate the Assets. TEP will retain ownership of and reserve any necessary easements for transmission facilities and associated property and lines from the facilities. In addition, because TEP will retain its transmission and distribution operations, the Company may enter into one or more joint use/management agreements with the purchasers of the Assets relating to systems or facilities necessary for the operations of each party.

Q. WHAT TEP CONTRACTS MAY BE ASSIGNED?

A. The divestiture of Assets will require the assignment or modification of several ancillary agreements. The most significant of those agreements are the coal and transportation agreements relating to Springerville and Irvington, and the project agreements relating to TEP's interests in remote generating facilities operated by other utilities.

Q. WILL TEP BE ALLOWED TO BID ON ANY ASSETS?

A. The auction process has been designed to provide all bidders access to the same information and due diligence materials regarding the generating assets. Should a TEP affiliate decide to bid on any or all of the Assets, appropriate "fire walls" will be established between the bidding affiliate and TEP personnel involved in the auction. The bidding affiliate will be required to enter into the Confidentiality and Auction Protocols Agreements modified to permit the affiliate to communicate only with NHI. The affiliate will have access to the same information and will be required to adhere to the same rules and standards of conduct as all the other bidders. Indications of interest and final bids from the affiliate will be delivered to

NHI as an independent third party, be opened first and evaluated with the other bids prior to disclosure to TEP.

VI. What Is the Current Market for Generating Assets?

Q. WHY HAVE OTHER UTILITIES CHOSEN AN AUCTION SALE?

A. As stated earlier, the most viable options considered for divestiture of utility assets are an auction sale or a negotiated sale. Each has its advantages and disadvantages. NHI recently completed the sale of generating assets for Southern California Edison ("SCE") through an auction process. The reasons SCE chose to do an auction are similar to the reasons that NHI has recommended TEP proceed with an auction: provide the greatest measure of assurance regarding the consequences of divestiture, ensure the best price for the assets, to attract the largest number of potential bidders, and to avoid unnecessary delay. NHI is currently conducting an auction for the 1340 MW Centralia Generating Station, in the State of Washington, for these same reasons.

Q. WHAT ARE SOME OF THE OTHER UTILITY AUCTIONS THAT HAVE BEEN ANNOUNCED?

A. Across the country, the electric utility market is undergoing substantial and fundamental changes. Many states, like Arizona, are strongly encouraging their traditionally integrated electric utilities to separate into non-regulated generating companies and regulated transmission and distribution companies. Most utilities have chosen to date to sell their soon to be non-regulated businesses including generation, and used or plan to use an auction process in almost every case. Fifteen utilities, including TEP, have announced intentions to divest some or all of their generation assets. The total megawatts for sale are approximately 38,000 MW of which 15,000 MW is coal. The two utilities with announced impending auction sales nearest TEP are Nevada Power and PG&E (California). Exhibit A lists the announced, but not completed, utility generation divestiture activity in the U.S.

Q. WHAT IS THE LIKELIHOOD OF A SUCCESSFUL AUCTION BY TEP?

A. Over the past two years, the market has been robust for domestic generating assets. Approximately 15 utilities have sold mostly gas-fired generating assets for prices from less than one to over five times book value. The five coal-fired facility sales included in the above group yielded proceeds in the range of one to over three times book value. A list of the generating assets that have been sold in the past two years is provided in Exhibit B. There is currently little generation sale activity in the Southwest. That lack of activity should make potential bidders interested in the auction, and the prices recently obtained for generation assets have been attractive. Accordingly, we believe there is a high likelihood the auction process proposed by TEP will result in the realization of the maximum value for its generating assets.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit A

List of Recently Announced Utility Auctions

Seller	Timing	Fuel Type(s)	Total Capacity (MW)	Coal Capacity (MW)
Central Hudson	By Q2.01	Coal, Gas, Oil	972	366
Con Edison	By Q1.99	Gas, Oil	3,665	0
Duquesne	Early 1999	Coal, Nuclear, Oil	3,035	2,138
ENOVA	By Q4.98	Gas, Oil, Nuclear	1,897	0
Nevada Power/ Sierra Pacific Resources	NA	Coal, Gas, Oil, Hydro	2,725	1,343
NIMO	By Q4.98	Coal, Gas, Oil, Hydro	4,217	1,300
Northeast Utilities	By Q4.98	Coal, Gas, Oil, Hydro	3,482	NA
Orange & Rockland	By Q2.99	Coal, Gas, Oil, Hydro	984	460
PacifiCorp (Centralia)	By Q4.98	Coal	1,340	1,340
PG&E	1998	Gas, Oil, Geothermal	4,289	0
Plains Electric G&T Cooperative	1999	Coal, Gas	278	250
Portland General Electric	By 1998	Coal, Gas, Oil, Hydro	3,363	712
Unicom (CWE)	By Q3.99	Coal	5,576	5,576
Unisource (Tucson Electric)	By Q1.01	Coal, Gas	1,992	1,182
Western Massachusetts Electric	By Q1.99	Oil, Gas, Hydro	290	209
			38,150	14,876

Exhibit B

List of Recently Completed Utility Auctions

(Dollars in millions, except price per kW)

Date Ann.	Buyer	Seller	Plant	Type	Net MW	Total Price	Book Value	Price/kW	Price to Book
11/09/98	Sithe Energies	GPU	23 power plants and 18 generation development properties	Various	4,117	$1,680	$791	$408	2.12
11/09/98	FirstEnergy	GPU	20% interest in Seneca hydroelectric generating station	Hydro	87	43	11	494	3.98
11/02/98	PP&L Global	Montana Power	11 Hydroelectric plants, 2 Coal-fired plants	Hydro, Coal	1,556	988	637	635	1.55
11/02/98	PP&L Global	Puget Sound/Portland General	1058-MW interest in Montana Power's 4-unit Colstrip Plant	Coal-fired	1,058	598	464	565	1.29
10/15/98	NRG	Eastern Utilities Associates	Somerset Station (160 MW)	Various	160	55	31	344	1.80
10/02/98	Wisconsin Energy	United Illuminating	Bridgeport Station Harbor Station (590 MW oil & coal), New Haven Harbor Station (466 MW oil & gas)	Various	1,056	272	218	258	1.25
09/28/98	PP&L Global	Bangor Hydro-Electric Company	8 hydro units, and Wyman Unit 4 (52 MW share)	Hydro, Oil	89	89	49	998	1.80
08/03/98	AES Corporation	NYSEG Generation	Kintigh Station (675 MW), Milliken Station (300 MW), Greenidge Station (160 MW), Goudey Station (125 MW), Hickling Station (70 MW), and Jennison Station (70 MW).	Coal-fired	1,400	950	886	679	1.07
08/03/98	Edison Mission	GPU & NYSEG	1,884-MW Homer City Electric Generation Plant	Coal-fired	1,884	1,800	540	955	3.33
07/07/98	WPS Resources	Maine Public Service	Wyman Unit 4 (20.7 MW share), several small diesel and hydro plants.	Various	91.8	37	12	406	3.20
05/27/98	Southern Energy Inc.	Commonwealth Energy System	Canal Unit 1, Canal Unit 2 (50% interest), five diesel generators, Kendall Station, Kendall Jets, 1.4% interst in Wyman Unit 4	Various	984	462	79	470	5.85

03/25/98	Houston Industries	Southern California Edison	(1)	Ormond Beach	Gas-fired	1,500	40	141	27	0.38
02/04/98	NRG/Destec	Southern California Edison	(1)	Long Beach	Gas-fired	530	30	98	56	0.30
01/06/98	FPL Group	Central Maine Power		91 hydro units (373 MW), 31 MW of wood capacity and 781 MW of fossil-fueld (3 plants)	Various	1,185	846	240	714	3.53
12/10/97	Sithe Energies	Boston Edison		Mystic, New Boston, L Street, Edgar Framingham, West Medway, Wyman	Oil & Gas	1,987	536	450	270	1.19
11/24/97	AES	Southern California Edison	(1)	Alamitos, Huntington Beach, Redondo	Gas-fired	3,956	781	228	197	3.42
11/24/97	Houston Industries	Southern California Edison	(1)	Coolwater, Mandalay, Ellwood, Etiwanda	Gas-fired	2,276	237	127	104	1.87
11/24/97	NRG/Destec	Southern California Edison	(1)	El Segundo	Gas-fired	1,020	88	71	86	1.23
11/24/97	Thermo Ecotek	Southern California Edison	(1)	San Bernardino and Highgrove	Gas-fired	280	10	-6	34	NM
11/18/97	Duke Energy	PG&E		Morro Bay, Moss Landing, and Oakland	Gas-fired	2,645	501	380	189	1.32
08/07/97	US Generating	NEES		3 thermal plants, 15 hydro-electric 23 power purchase contracts	Various	5,100	1,590	1,100	312	1.45
10/31/96	Allegheny Power	Duquesne Light & Power		Fort Martin (50% interest of unit one)	Coal-fired	276	170	45	616	3.78